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August 29, 2019

<u>**BY ELECTRONIC DELIVERY**</u>

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Richmond, VA 23219

Commonwealth of Virginia ex rel. State Corporation Commission,
In re: Virginia Electric and Power Company's Update to Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.
<u>Case No. PUR-2019-00141</u>

Dear Mr. Peck:

Please find enclosed for filing in the above-captioned proceeding, an electronic copy of the 2019 Update to the 2018 Integrated Resource Plan (the "2019 Update") of Virginia Electric and Power Company filed pursuant to § 56-597 *et seq.* of the Code of Virginia, the Commission's December 23, 2008 Order Establishing Guidelines for Developing Integrated Resource Plans issued in Case No. PUE-2008-00099 ("Order Establishing Guidelines"), and the Integrated Resource Planning Guidelines ("Guidelines") established therein. As required by prior orders of the Commission, a reference index identifying the sections of the 2019 Update that comply with the Guidelines and with the requirements of recent Plan orders is enclosed herein.

Also enclosed in this filing is a cover letter from Paul D. Koonce, President and Chief Executive Officer of the Power Generation Group, which provides an overview of the Company's 2019 Update.

Please do not hesitate to contact me if you have any questions in regard to this filing.

Very truly yours,

Vishwa B. Link

Vishwa B. Link

Enclosure

cc: William H. Chambliss, Esq.
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August 29, 2019

Joel H. Peck, Clerk
Virginia State Corporation Commission
C/O Document Control Center
1300 East Main Street
Richmond, VA 23219

Re: Case No. PUR-2019-00141

Dear Mr. Peck:

Virginia Electric and Power Company ("the Company") is pleased to submit to the Virginia State Corporation Commission ("Commission") its 2019 update ("2019 Update") to its 2018 Integrated Resource Plan (the "2018 Plan"). The 2019 Update is submitted in accordance with § 56-599 of the Code of Virginia and the Commission's Integrated Resource Planning Guidelines issued on December 23, 2008. Simultaneously, the 2019 Update is also being filed with the North Carolina Utilities Commission ("NCUC") in accordance with § 62-2 of the North Carolina General Statutes and Rule R8-60 of the NCUC's Rules and Regulations.

The 2019 Update reflects the Company's belief that regulation of power station carbon dioxide ("CO_2") emissions is imminent, whether through federal or state initiatives, or both. At the federal level, the U.S. Environmental Protection Agency released the final version of the Affordable Clean Energy ("ACE") rule on June 19, 2019. The ACE rule, which supplants the Clean Power Plan, requires heat rate efficiency improvements at existing coal-fired units based on a range of candidate technologies. The ACE rule requires that each state determine which of the candidate technologies apply to each coal-fired unit based on consideration of remaining useful plant life and other factors, such as reasonableness of cost.

At the state level, the Virginia Department of Environmental Quality ("DEQ") published a final rule on May 27, 2019, that establishes a state cap-and-trade program for electric generating units in Virginia. The final regulation has removed specific references to the Regional Greenhouse Gas Initiative ("RGGI") program. However, the regulation remains structured in such a way that the Virginia program could link with a regional program such as the existing nine-state RGGI program.

The final rule includes a provision that accounts for the delayed implementation given language in the state budget bill (signed by Virginia Governor Ralph Northam on May 2, 2019). Specifically, implementation of most elements of the program, including requirements for holding and surrendering CO_2 allowances, will likely be delayed to the calendar year following authorization for funding to implement the program. Nevertheless, the final regulation became effective on June 26, 2019. The regulation includes a starting (baseline) statewide CO_2 emissions cap of 28 million tons in 2020. The cap is reduced by about 3 percent per year through 2030, resulting in a 2030 cap of 19.6 million tons. However, the starting cap could be adjusted if initial implementation of the rule is delayed.

Because of the uncertainty regarding the final form of carbon emission regulations, the 2019 Update presents options ("Alternative Plans") representing plausible future long-term paths for meeting the energy needs of the Company's customers. The Company also offers a strategic plan for the next five years in its Short-Term Action Plan.

The Update Reflects the Transition to a Lower Emission Rate Future

The Company has been a leader in reducing carbon emissions, having begun its transition to a lower carbon emissions generating fleet well before the proposed federal and state carbon regulations discussed in the 2019 Update. Between 2000 and 2018, the carbon emissions of the Company's units serving Virginia declined by 32% while power production from these units increased 12%. On March 25, 2019, the Company committed to an 80% reduction in greenhouse gas emissions by 2050. Simultaneous to that announcement, the Company also put forth a five-year plan that includes development of offshore wind, a new pumped hydroelectric storage facility, additional solar photovoltaic ("PV") resources, and distribution system modernization.

Carbon regulations are not the only driver for clean energy. Support for carbon reduction is reflected in feedback the Company has received from customers seeking clean energy. Indeed, many of the Company's customer segments, including data center customers, colleges, universities, financial institutions, retail chains, and commercial customers are seeking renewable energy solutions. Increased interest in clean energy is also reflected by participation in the Company's Green Power Program, which has experienced a customer compound annual growth rate ("CAGR") of approximately 20% for the years 2009 through 2018.

Renewable resources are becoming a more cost-effective means of meeting the growing energy demands of customers. This is particularly true of solar power. The continuing development of solar PV technology has made this type of generation cost-competitive with other, more traditional forms of generation. Supplemented by units using lower-emitting natural gas, solar PV will play an increasingly important role in the Company's generation fleet serving customers in Virginia and North Carolina. In fact, all three of the Alternative Plans presented in the 2019 Update, including the least-cost plan, call for the potential development of 840 megawatts ("MW") of additional solar capacity by 2022. By 2044, Alternative Plans A, B, and C would expand the Company's solar fleet by 5,400 MW, 7,080 MW and 5,640 MW respectively.

The Virginia General Assembly affirmed the growing importance of renewable energy generation in passing the Grid Transformation and Security Act of 2018 (the "GTSA"), which was signed into law by Governor Ralph Northam on March 9, 2018. The law found that up to 5,000 MW of utility-scale electric generating facilities powered by solar and wind energy statewide is in the public interest, along with up to an additional 500 MW of non-utility scale solar or wind generating facilities, including rooftop solar installations. The GTSA also encouraged electric distribution grid transformation projects, in part to facilitate the integration of renewable generation resources into the Company's system.

While acknowledging the rapidly increasing role of renewable resources, the 2019 Update identifies an economical blend of resources capable of meeting the future energy needs of the Company's customers under a variety of scenarios. The 2019 Update recognizes the continued importance of lower-emissions natural gas as a significant source of electric generation, with all three Alternative Plans including potential development of 2,425 MW of additional combustion turbine ("CT") capacity by 2044.

The 2019 Update includes more detail on the Company's plans for energy storage and offshore wind. As part of the Short-Term Action Plan, over the next five years, the Company expects to continue development of energy storage alternatives, including battery storage and a new pumped hydroelectric storage facility in western Virginia. On August 2, 2019, the Company submitted its first application to participate in the Virginia pilot program for electric power storage batteries established by the Commission pursuant to the GTSA. The application presents three projects with an aggregate capacity of 16 MW. The Company may seek approval of additional projects in future applications up to the 30 MW authorized under the pilot program. Meanwhile, the Company continues to evaluate the potential for construction of a pumped hydroelectric storage facility at a site in Tazewell County and will spend the remainder of 2019 and part of 2020 conducting more extensive surveys of the proposed site. The project could generate thousands of construction jobs as well as provide a major new source of local taxes for the region. With regard to offshore wind, the Company is constructing the Coastal Virginia Offshore Wind demonstration project and will continue development of the first tranche (852 MW) of utility-scale offshore wind generation.

The 2019 Update also continues to recognize that nuclear power must continue to play a major role in power generation in a lower-carbon, lower-emissions future. Each of the Alternative Plans assumes that the Company's nuclear generation fleet in Virginia, which includes two reactors at Surry Power Station and two at North Anna Power Station, will receive 20-year operating license extensions from the U.S. Nuclear Regulatory Commission. Relicensing the units will ensure that these reactors continue their zero-carbon production of electricity into the second half of the 21st century. The Surry and North Anna nuclear units continue to be by far the largest source of zero-emissions generation for the Company. Their operation avoids the release of approximately 22 million tons of CO_2 per year. Approximately 12,500 MW of solar PV facilities covering about 100,000 acres would be needed to match the nuclear units' annual power output.

In addition to new and relicensed generation, the 2019 Update also evaluates demand-side management ("DSM") programs to help customers conserve energy or reduce system peak loads. In this 2019 Update, the Company includes DSM programs that received Commission approval. On July 12, 2019, in North Carolina, the Company filed for approval of additional DSM programs. The Company is currently awaiting the Final Order for these program applications. Like the 2018 Compliance Filing, the 2019 Update Plan includes a generic energy efficiency program designed to achieve the target of $870 million of energy efficiency expenditures by 2028.

Alternative Plans Examined by the Company

The 2019 Update presents the three Alternative Plans described below.

- Plan A: No CO_2 Tax – Plan A is based on the No CO_2 tax pricing scenario and is designed using least cost modeling methodology with no consideration of CO_2 emissions. Plan A represents the least cost plan consistent with the guidelines in prior Commission Orders.

- Plan B: RGGI – Plan B assumes a pricing scenario where Virginia joins RGGI in 2021 and a Federal CO_2 Program is implemented in 2026. Plan B is designed such that the Company's generation expansion plan meets the objectives of the GTSA in terms of new solar and wind generation and the battery pilot program.

- Plan C: Sustainable Investment – Plan C assumes a pricing scenario where a Federal CO_2 Program is implemented in 2026. Plan C is designed such that the Company's generation expansion plan meets the objectives of both the GTSA and Senate Bill 1418 (legislation enacted in 2017 that supports construction of pumped hydroelectric generation and storage facilities utilizing on-site and off-site renewable energy resources) in terms of new solar and wind generation, the battery pilot program, and pumped hydroelectric storage facility development.

Common Elements of the Alternative Plans

Major common elements of the three Alternative Plans within the study period 2020 through 2044 include:

- **Solar (Utility and Non-Utility Generators):** Development of 5,400 MW of solar PV generation by 2044.
- **Wind:** Construction and operation of the Coastal Virginia Offshore Wind demonstration project. The project is due to be operational in 2020.
- **Nuclear:** 20-year license extensions for the four Company-owned nuclear units at Surry and North Anna Power Stations. The Surry units would be relicensed by 2032 and 2033, and the North Anna units by 2038 and 2040.
- **Natural Gas:** The Alternative Plans call for the addition of 10 natural gas-powered CT units with a combined capacity of approximately 2,425 MW by 2044. They would operate in pairs, each representing 485 MW of capacity.
- **Demand-Side Management:** Implementation of approved DSM programs, capable of reducing overall system peak demand by 265 MW by 2034.
- **Potential Retirements (Fossil Fuels & Biomass):** All plans retire Possum Point 5 in 2021 and Yorktown 3 in 2023.

Additional Generation and Retirements in Alternative Plans

In addition to the common elements listed above, the various Alternative Plans contain additional resources and potential retirements by 2044, the end of the 25-year study period.

- Plan B (RGGI) includes 1,680 MW of additional solar and one additional pair of CT units totaling 485 MW.
- Plan C (Sustainable Investment) includes 240 MW of additional solar; two pairs of CT units at 970 MW; the first tranche (852 MW) of utility-scale offshore wind generation; and the 300 MW proposed pumped hydroelectric storage facility.
- Plans B and C both include the 30 MW of battery storage authorized under the Virginia pilot program for electric power storage batteries established by the Commission pursuant to the GTSA.
- Plans B and C both include the potential retirement of 1,453 MW of coal units: Chesterfield 5 & 6 (1,014 MW) and Clover 1 and 2 (439 MW).

Cost of Alternative Plans

Plans B and C, both of which envision compliance with state and federal carbon regulations would impose higher costs on customers. The net present value ("NPV") of costs associated with the two plans including carbon regulations are greater than the NPV of the No CO_2 Tax plan by $6.52 billion for Plan B (RGGI) and $7.48 billion for Plan C (Sustainable Investment).

Dominion Energy Virginia's Commitment

Dominion Energy Virginia remains committed to its longstanding goals of operating responsibly; maintaining a diverse, balanced generation fleet that avoids over-reliance on a single fuel type or technology; and providing reliable and affordable energy to its customers. These goals guided the development of the 2019 Update and will guide the Company in the future.

Sincerely,

Paul D. Koonce

2019 Update - Reference Index

Order / Guideline	2019 Update Section	Requirement
Guideline (E)	*Section 7* Short-Term Action Plan	*Each filing shall include a five-year action plan* that discusses those specific actions currently being taken by the utility to implement the options or activities chosen as appropriate per the IRP.
Guideline (E)	N/A	If a utility considers certain information in its IRP to be proprietary or confidential, the utility may so designate, file separately and request such treatment in accordance with the Commission's Rules of Practice and Procedures.
Guideline (E)	Section 2 Discussion of Significant Events Section 3 The 2019 Update	Additionally, by September 1 of each year in which a plan is not required, each utility shall file a narrative summary describing any significant event necessitating a major revision to the most recently filed IRP, including adjustments to the type and size of resources identified. If the utility provides a total system IRP in another jurisdiction by September 1 of the year in which a plan is not required, filing the total system IRP from the other jurisdiction will suffice for purposes of this section.
Case No. PUE-2016-00049 Final Order at 3 Case No. PUE-2015-00035 Final Order at 18	2019 Update Reference Index	Dominion shall continue to comply with all requirements directed in prior IRP orders, including the requirement to include an index that identifies the specific location(s) within the IRP that complies with each such requirement.
Case No. PUE-2013-00088 Final Order at 5-6	Section 2.c Nuclear Relicensing	The Company shall also provide status updates on any discussions it engages in with the United States Nuclear Regulatory Commission on a possible extension for the operating licenses for Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2, in its future IRP and IRP update filings.

Dominion Energy®

Virginia Electric and Power Company's 2019 Update to 2018 Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

Case No. PUR-2019-00141
Docket No. E-100, Sub 157

Filed: August 29, 2019

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VIRGINIA ELECTRIC AND POWER COMPANY
2019 UPDATE TO 2018 INTEGRATED RESOURCE PLAN

1. INTEGRATED RESOURCE PLAN UPDATE OVERVIEW

a. Introduction to the 2019 Update

Virginia Electric and Power Company (the "Company") hereby files its 2019 update ("2019 Update") to its 2018 Integrated Resource Plan (the "2018 Plan") with the State Corporation Commission of Virginia ("SCC") in accordance with § 56-599 of the Code of Virginia ("Va. Code") and the SCC's Integrated Resource Planning Guidelines issued on December 23, 2008 ("SCC Guidelines").[1] The Company also files this 2019 Update with the North Carolina Utilities Commission ("NCUC") in accordance with § 62-2 of the North Carolina General Statutes ("NCGS") and Rule R8-60 of the NCUC's Rules and Regulations ("NCUC Rules").

The 2019 Update was prepared for the Dominion Energy Load Serving Entity ("DOM LSE") and represents the Company's service territories in the Commonwealth of Virginia and the State of North Carolina, which are part of the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization ("RTO").

Since the Company first began filing integrated resource plans (generally referred to as "Plans") with both the SCC and NCUC in 2009, this is the first year that an update to the most recently filed Plan (generally referred to as "Updates") was permitted for filing in both jurisdictions. Accordingly, the Company submits this 2019 Update in compliance with Section (E) of the SCC Guidelines and Rule R8-60(h)(2) of the NCUC Rules, and consistent with any requirements identified in prior relevant orders that continue to be applicable to Update filings.

As required by both the SCC Guidelines and the NCUC Rules, the Company's objective in this 2019 Update is to provide a discussion of significant events requiring a major revision to the most recently filed Plan—here, the 2018 Plan along with the 2018 Compliance Filing filed on March 7, 2019. The regulation of electric sector carbon dioxide ("CO_2") emissions remains the most significant uncertainty. From a public policy perspective, the passage of the Grid Transformation and Security Act of 2018 (the "GTSA")[2] by the Virginia General Assembly established policy objectives for the Commonwealth, including the development of 5,000 megawatts ("MW") of solar, onshore wind, and offshore wind generation facilities by 2028 on a statewide basis. These policy objectives coupled with the 2017 Virginia General Assembly passage of Senate Bill ("SB") 1418 supporting construction of pumped hydroelectric generation and storage facilities utilizing on-site and off-site renewable energy resources, underscore the larger role that renewable energy will have in Virginia's future.

Support for these overall public policy goals is reflected in feedback the Company has received from customers opting for clean energy. Indeed, many of the Company's customer segments, including data center customers, colleges, universities, financial institutions, retail chains, and commercial customers are all seeking renewable energy solutions. Other

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[1] *Commonwealth of Virginia, ex rel. State Corporation Commission, Concerning Electric Utility Integrated Resource Planning Pursuant to §§ 56-597 et seq. Code of Virginia*, Case No. PUE-2008-00099, Order Establishing Guidelines for Developing Integrated Resource Plans (Dec. 23, 2008) ("SCC Order Establishing Guidelines").

[2] 2018 Virginia Acts of Assembly, Chapter 296 (effective July 1, 2018).

customers are opting for clean energy as well, as reflected by participation in the Company's Green Power Program, which has experienced a customer compound annual growth rate ("CAGR") of approximately 20% for the years 2009 through 2018. In addition, net metering customers have increased at an approximately 30% CAGR for the years 2014 through 2018 (approximately 40% CAGR in terms of kilowatts ("kW")). Moreover, Virginia cities including Charlottesville, Alexandria, Richmond, and Norfolk are all developing climate action initiatives with the intent of lowering each area's overall carbon footprint.

The Company is keenly aware of the societal trends identified above and, therefore, continues to steadily transition its generation fleet and transmission and distribution systems to meet a green future. Examples of this transition include:

1. The retirement of over 2,300 MW of coal-fired and high heat rate oil- and natural gas-fired generation over the past 10-year period;
2. The development of the Coastal Virginia Offshore Wind Project ("CVOW") along with the first tranche of offshore wind generation off the coast of Virginia;
3. The development of approximately 3,000 MW of solar photovoltaic ("PV") generation by the end of 2022;
4. The procurement of approximately 770 MW of solar PV non-utility generation ("NUG") over the past 10 years, most of which is in the Company's North Carolina service territory;
5. Continued work to extend the licenses of the Company's nuclear units at both Surry and North Anna;
6. The continued progress towards transformation of the Company's distribution system (the "Grid Transformation Plan" or "GT Plan") to provide an enhanced platform for distributed energy resources ("DERs"), which will in turn permit more efficient deployment of demand-side management ("DSM") measures;
7. The continued developmental work associated with energy storage technology, which includes a new pumped storage hydroelectric facility in Virginia and the proposed deployment of three battery energy storage system ("BESS") pilot programs; and
8. The future development of efficient and reliable combustion turbine ("CT") natural gas-fired generation as a backstop to intermittent renewable resources at a system level.

The Company's gradual yet deliberate transitional approach provides customers a path to green energy while maintaining the standard of reliability necessary to fuel Virginia's modern economy.

b. The 2018 Plan

In 2018, a full Plan filing was required by provisions of Virginia and North Carolina law. Accordingly, on May 1, 2018, the Company filed its 2018 Plan with the SCC (Case No. PUR-2018-00065) and with the NCUC (Docket No. E-100, Sub 157).

The SCC held a hearing on the 2018 Plan beginning on September 24, 2018. On December 7, 2018, the SCC issued an Order ("SCC Dec. 2018 Order") directing the Company to "correct and refile its 2018 [Plan]" subject to provisions specifically set forth in the SCC Dec. 2018 Order. On March 7, 2019, the Company submitted the required filing in compliance with the SCC Dec. 2018 Order (*i.e.*, the 2018 Compliance Filing)[3] and requested that the

[3] The Company contemporaneously filed the 2018 Compliance Filing in the 2018 Plan NCUC docket (Docket No. E-100, Sub 157).

SCC issue a determination finding the Company's 2018 Plan, together with the submission of the 2018 Compliance Filing, reasonable and in the public interest pursuant to Va. Code § 56-599 E. The SCC held a hearing on the 2018 Compliance Filing on May 8, 2018.

On June 27, 2019, the SCC issued its Final Order on the 2018 Plan ("SCC Final Order"), finding, among other things, that the "2018 [Plan], as originally filed on May 1, 2018, and amended on March 7, 2019: (1) complies with the directives in the [SCC Dec. 2018 Order]; and (2) is reasonable and in the public interest for the specific and limited purpose of filing the planning document as mandated by § 56-597 et seq. of the Code."[4]

The NCUC held a hearing on the 2018 Plan on February 4, 2019. The NCUC issued a final order on the 2018 Plan on August 27, 2019 ("NCUC Final Order"), and stated that the "[NCUC] finds and concludes that [Dominion Energy North Carolina's ("DENC's")] 2018 [Plan] is adequate for planning purposes, and should be accepted, subject to DENC's 2019 IRP Update."[5]

2. DISCUSSION OF SIGNIFICANT EVENTS

As noted above, both the SCC Guidelines and the NCUC Rules require Updates to include a discussion of significant events requiring a major revision to the most recently filed Plan—here, the 2018 Plan. Specifically, Section (E) of the SCC Guidelines requires:

> Additionally, by September 1 of each year in which a plan is not required, each utility shall file a narrative summary describing any significant event necessitating a major revision to the most recently filed IRP, including adjustments to the type and size of resources identified. If the utility provides a total system IRP in another jurisdiction by September 1 of the year in which a plan is not required, filing the total system IRP from the other jurisdiction will suffice for purposes of this section.[6]

Similarly, the Rule R8-60(h)(2) of the NCUC Rules requires:

> By September 1 of each year in which a biennial report is not required to be filed, an update report shall be filed with the Commission containing an updated 15-year forecast of the items described in subparagraph (c)(1), as well as a summary of any *significant amendments or revisions to the most recently filed biennial* report, including amendments or revisions to the type and size of resources identified, as applicable.[7]

Both the term "significant" and "major" require judgment on the part of the Company to interpret. Therefore, the Company is including a discussion of significant external events that, in its opinion, have required revision to the 2018 Plan in this 2019 Update.

[4] SCC Final Order at 3 (internal footnote omitted).
[5] NCUC Final Order at 86.
[6] SCC Order Establishing Guidelines, Attachment B, Section (E) at p. 5.
[7] NCUC Rule R8-60(h)(2).

a. Environmental Regulations

As with prior Plan filings, the area of greatest uncertainty remains federal and/or state regulation of electric sector CO_2 emissions. The Company maintains that some form of future CO_2 regulation is imminent.

On the federal level, the U.S. Environmental Protective Agency ("EPA") released the final version of the Affordable Clean Energy ("ACE") rule, the replacement for the Clean Power Plan ("CPP") on June 19, 2019. The final ACE rule combines three distinct EPA actions.

First, through the ACE rule, the EPA finalized the repeal of the CPP. It also asserted that the repeal is intended to be severable, such that it will survive even if the remainder of the ACE rule is invalidated.

Second, through this action, the EPA finalized the ACE rule, which comprises EPA's determination of the Best System of Emissions Reduction ("BSER") for existing coal-fired power plants and establishment of the procedures that will govern states' promulgation of standards of performance for existing electric generating units ("EGUs") within their borders. The EPA sets the final BSER as heat rate efficiency improvements based on a range of candidate technologies that can be applied inside the fence-line of an EGU. Rather than setting a specific numerical standard of performance for these units, the EPA's rule requires that each state determine which of the candidate technologies apply to each coal-fired unit based on consideration of remaining useful plant life and other factors, such as reasonableness of cost. Each state must then establish standards of performance based on the degree of emission reduction achievable with the application of the applicable elements of BSER.

Third, through the ACE rule, the EPA finalized a number of changes to the implementing regulations for the timing of state plans for this and future Section 111(d) rulemakings of the Clean Air Act. Based on the changes, states will have three years from when the rule is finalized to submit a plan to the EPA, at which point the EPA has one year to determine whether the plan is acceptable. If states do not submit a plan or if their submitted plan is not acceptable, the EPA will have two years to develop a federal plan.

At the state level, on May 27, 2019, the Virginia Department of Environmental Quality ("VDEQ") published a final rule that established a state cap-and-trade program for EGUs in Virginia. The final rule included a section that allowed for delayed VDEQ implementation of the rule to address amendments to the state budget bill (signed by the Virginia Governor) that prohibited VDEQ from continued work on the rule. Specifically, implementation of most elements of the program, including requirements for holding and surrendering CO_2 allowances, likely will be delayed to the calendar year following Virginia General Assembly or Virginia Governor authorization for appropriating funding to implement the program. The earliest date for this action would be January 1, 2021.

Nevertheless, the final regulation became effective on June 26, 2019, and included specific near-term requirements for affected entities under the program. These include:

- A requirement to submit to the VDEQ by August 25, 2019, the annual net-electric output (megawatt-hours or "MWh") for calendar years 2016, 2017, and 2018 for each EGU subject to the rule. This information will be used by the VDEQ to determine the CO_2 allowance allocations for the initial control period; and

- A requirement to submit to the VDEQ by January 1, 2020, a complete CO_2 budget permit application for each source with an applicable electric generating unit subject to the program.

In addition, the final VDEQ regulation has removed specific references to the Regional Greenhouse Gas Initiative ("RGGI") program. However, the regulation remains structured in a way that would allow for the Virginia program to link with a regional program such as the existing nine-state RGGI program.

Other key elements of the regulation as finalized are:

- The regulation includes a starting (baseline) statewide CO_2 emissions cap of 28 million tons in 2020. The cap is reduced by about 3 percent per year through 2030, resulting in a 2030 cap of 19.6 million tons. However, as noted above, the starting cap could be adjusted if initial implementation of the rule is delayed.

- The regulation no longer contains any references to continued cap reductions after 2030 that the VDEQ had included in prior versions of the rule.

- The regulation has reinstated language to clarify that affected units under the rule would only have to hold allowances for emissions associated with fossil fuel combustion. The added language assures that the Company's Virginia City Hybrid Energy Center ("VCHEC") will not have to hold allowances for emissions related to biomass co-firing.

- Although the regulation includes a new provision that would recognize eligible emissions offsets from other participating states in a regional trading program, it does not provide the opportunity to generate offsets from projects in Virginia. The VDEQ has indicated it may re-evaluate offset provisions during the next program review.

The Company continues to oppose Virginia's entry into a regional CO_2 cap-and-trade program such as that proposed by the VDEQ. The Company maintains that:

- Virginia's linkage to a RGGI-like program will encourage electricity imports from out-of-state sources that are more carbon intensive. This will result in highly efficient and lower emitting natural gas combined-cycle ("NGCC") facilities in Virginia operating less;

- Reductions in carbon emissions in Virginia as a result of the increased use of imported power will be offset by emission increases elsewhere within the North American Electric Reliability Corporation ("NERC") Eastern Interconnect, which includes all of PJM and the RGGI region;

- Increased imports of more carbon-intensive power will result in the carbon footprint per customer in Virginia increasing; and

- Virginia's participation in a regional program such as RGGI will result in additional cost to Virginia electricity consumers and make Virginia less competitive with neighboring non-RGGI states.

In North Carolina, the North Carolina Department of Environmental Quality ("NCDEQ") issued on August 16, 2019, a draft Clean Energy Plan for comment. This plan was required by North Carolina Governor Cooper's Executive Order No. 80 issued in the fall of 2018. A primary objective of NCDEQ's Plan is to recommend prospective strategies to achieve deep cuts to electric power sector carbon emissions in the state by 2030 (60-70% reduction goal below 2005 levels) with a goal of zero power sector carbon emissions by 2050. Section 4.1 of the NCDEQ Plan[8] presents a list of potential policy goals, which can generally be summarized into three major categories: 1) modernizing utility incentives; 2) requiring more comprehensive integrated utility system operations planning; and 3) modernizing the grid to support clean energy. The comment period on the NCDEQ Plan extends through September 9, 2019, and the Company plans to file comments.

b. Generation Retirements

In the PJM market, there are 44,684 MW of generation that have been or are planned to be retired between 2011 and 2022, of which 31,621 MW (71%) are coal-fired steam units and 4,673 MW (11%) are natural gas-fired units.[9] Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined-cycle ("CC") units burning low cost natural gas. These coal-fired steam units have an average age of 52.9 years and an average size of 195 MW.[10] The natural gas-fired units have an average age of 48.4 years and an average size of 87 MW.[11] Retirements have generally consisted of smaller subcritical coal-fired steam units and those without adequate environmental controls to remain viable in the future.

In March 2019, the Company announced the retirement of eleven units:

MW	Fuel	Name	Retirement Date
261	Coal	Chesterfield Units 3 & 4	2019
138	Coal	Mecklenburg Units 1 & 2	2019
267	Gas	Bellemeade	2019
227	Gas	Bremo Units 3 & 4	2019
316	Gas	Possum Point Units 3 & 4	2019
83	Biomass	Pittsylvania	2019
786	Oil	Possum Point Unit 5	2021

In making the decision to retire these units, the Company considered the effects on the power system, including reliability, system diversity, environmental issues, and minimizing long-term power costs to customers. These units were not economical and were not expected to be economical in the future.

Looking forward, based on current market conditions, the following table identifies existing Company coal- and oil-generating resources that may be at risk for retiring. The generators listed below should be considered as tentative for retirement only. The Company's final decisions regarding any unit retirement will be made at a future date.

[8] *See*, https://deq.nc.gov/energy-climate/climate-change/nc-climate-change-interagency-council/climate-change-clean-energy-16.
[9] 2018 State of the Market Report for PJM, at p. 572, Monitoring Analytics, LLC. *See*, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec12.pdf.
[10] *Id.*
[11] *Id.*

MW	Fuel	Name
1,014	Coal	Chesterfield Units 5 & 6
439	Coal	Clover Units 1 & 2
790	Oil	Yorktown Unit 3

The Company will continue to study these units and other existing generating resources for possible retirement. As part of this process, the Company evaluates large capital expenditures required to keep units in compliance with environmental regulations to the extent that the units are not retired. One current example is the capital required for Chesterfield Units 5 and 6 to meet the effluent limitation guidelines ("ELG").

c. Nuclear Relicensing

An application for a subsequent or second license renewal ("SLR") is allowed during a nuclear plant's first period of extended operation—that is, in the 40 to 60 years range of its service life. Surry Units 1 and 2 entered into that period in 2012 (Unit 1) and 2013 (Unit 2). North Anna Unit 1 entered into that period in 2018, and North Anna Unit 2 will enter into that period in 2020.

In November 2015, the Company notified the Nuclear Regulatory Commission ("NRC") of its intent to file for SLR for its two nuclear units (1,676 MW total) at Surry in order to operate an additional 20 years, from 60 to 80 years. As with other nuclear units, Surry was originally licensed to operate for 40 years and then renewed for an additional 20 years. The licenses for Surry's two units will expire in 2032 and 2033, respectively. In support of the application development, the NRC finalized guidance documents in early July 2017, related to developing and reviewing SLR applications. The Surry SLR application was submitted to the NRC on October 15, 2018, in accordance with Title 10 of the Code of Federal Regulations ("CFR") Part 54. In early December 2018, the application was accepted for review by the NRC. This is an important milestone in that the application met the NRC requirements to move forward with both the technical and environmental review processes, which are underway. The issuance of the renewed license is expected to take 18 months from the date when the application was accepted for review (*i.e.*, by June 2020). This will preserve the option to continue operation of Surry Units 1 and 2 until 2052 and 2053, respectively.

The Company also notified the NRC in November 2017, of its plans to file a SLR application for its two North Anna units in accordance with 10 CFR Part 54 in late 2020. The existing licenses for the two units will expire in 2038 and 2040, respectively. The issuance of the renewed licenses would follow successful NRC safety and environmental reviews tentatively in the 2022 timeframe.

d. Other Events

i. <u>Investor Day Presentation</u>

As discussed earlier in this 2019 Update, there is a strong societal movement toward the development of clean energy. On March 25, 2019, the Company announced that it is committed to an 80% reduction in greenhouse gas ("GHG") emissions by 2050. Simultaneous to that announcement, the Company also put forth a five-year plan that continues the Company's progress toward achieving this goal, including the development of offshore wind, a new pumped storage hydroelectric facility, continued solar PV development and a distribution system modernization program.

ii. New Legislation

In its 2019 Session, the Virginia General Assembly passed various legislation related to regulated utilities in the Commonwealth. Relevant to the integrated resource planning ("IRP") process were SB 1355[12] and House Bill ("HB") 2547.[13] SB 1355 requires that any closure plan for the coal ash impoundments at the Company's Bremo Power Station, Chesapeake Energy Center, Chesterfield Power Station, and Possum Point Power Station include either (i) recycling the ash, or (ii) containing the ash in a lined landfill facility. HB 2447 requires the Company to convene a stakeholder process to receive input on the development of time-varying rates, peak shaving programs, and renewable distributed energy resources. To date, the Company has developed a stakeholder group, hired a facilitator (Navigant Consulting, Inc.), and conducted several stakeholder meetings.

iii. Capacity Auction

In a June 2018 Order, the Federal Energy Regulatory Commission ("FERC") found PJM's Tariff to be unjust, unreasonable, and unduly discriminatory because it fails to protect the capacity market from the price suppressive impacts of out-of-market support to new and existing resources.[14] FERC also instituted a paper hearing under Section 206 of the Federal Power Act to determine the just and reasonable replacement rate proposed by PJM. Testimony was submitted in late 2018, and FERC action on the paper hearing remains pending.

Subsequently, FERC granted PJM's request to waive the auction timing requirements of its Tariff to allow for a delay of the 2019 Base Residual Auction ("BRA") for the 2022-2023 delivery year from May 2019 to August 2019. PJM sought to move the BRA, in part, to ensure that it had sufficient time to conduct the auction based on the just and reasonable replacement rate established in this proceeding.

In April 2019, with action on the replacement rate still pending, PJM notified FERC of its intention to run the auction under existing rules unless FERC directed otherwise. On July 25, 2019, FERC issued an order directing PJM not to run the BRA in August 2019.[15]

The Company agrees that a delay of the 2022-2023 BRA will permit FERC the time it needs to carefully consider the number of proposed capacity reforms and allow market participants additional time to prepare for any rule changes that will impact the future capacity auctions.

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[12] 2019 Virginia Acts of Assembly, Chapter 651 (effective July 1, 2019).
[13] 2019 Virginia Acts of Assembly, Chapter 742 (effective July 1, 2019).
[14] *See, Calpine Corporation, Dynegy Inc., Eastern Generation, LLC, Homer City Generation, L.P., NRG Power Marketing LLC, GenOn Energy Management, LLC, Carroll County Energy LLC, C.P. Crane LLC, Essential Power, LLC, Essential Power OPP, LLC, Essential Power Rock Springs, LLC, Lakewood Cogeneration, L.P., GDF SUEZ Energy Marketing NA, Inc., Oregon Clean Energy, LLC and Panda Power Generation Infrastructure Fund, LLC v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (June 29, 2018) (Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act) *reh'g pending.*
[15] *See, Calpine Corp. v. PJM Interconnection, L.L.C.*, 168 FERC ¶ 61,051 (July 25, 2019) (Order on Motion for Supplemental Clarification).

3. THE 2019 UPDATE

As discussed above, the Company's objective in this 2019 Update is to provide a discussion of significant events requiring a revision to the most recently filed Plan. Based on these events, the Company has made adjustments to the type and size of resources identified in the 2018 Plan. As always, the Company's options for meeting these future needs are: (i) supply-side resources, (ii) demand-side resources, and (iii) market purchases. A balanced approach—which includes the consideration of options for maintaining and enhancing rate stability, increasing energy independence, promoting economic development, and incorporating input from stakeholders—will help the Company meet growing demand while protecting customers from a variety of potential challenges and negative impacts.

a. Analytical Tools and Processes

The Company primarily used the PLEXOS model ("PLEXOS"), a utility modeling and resource optimization tool, to develop this 2019 Update over the 25-year period beginning in 2020 and continuing through 2044 (the "Study Period"), using 2019 as the base year. The 2019 Update is based on the Company's current assumptions regarding commodity prices, environmental regulations, construction and equipment costs, DSM programs, and many other regulatory and market developments that may occur during the Study Period. The Company used an adjusted PJM load forecast, as described below.

b. Capacity and Energy Positions

Based on the PJM load forecast and the Company's approved future resources, and assuming no new builds, Figures 1 and 2 represent the Company's current capacity and energy positions.

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Figure 1: Capacity Position

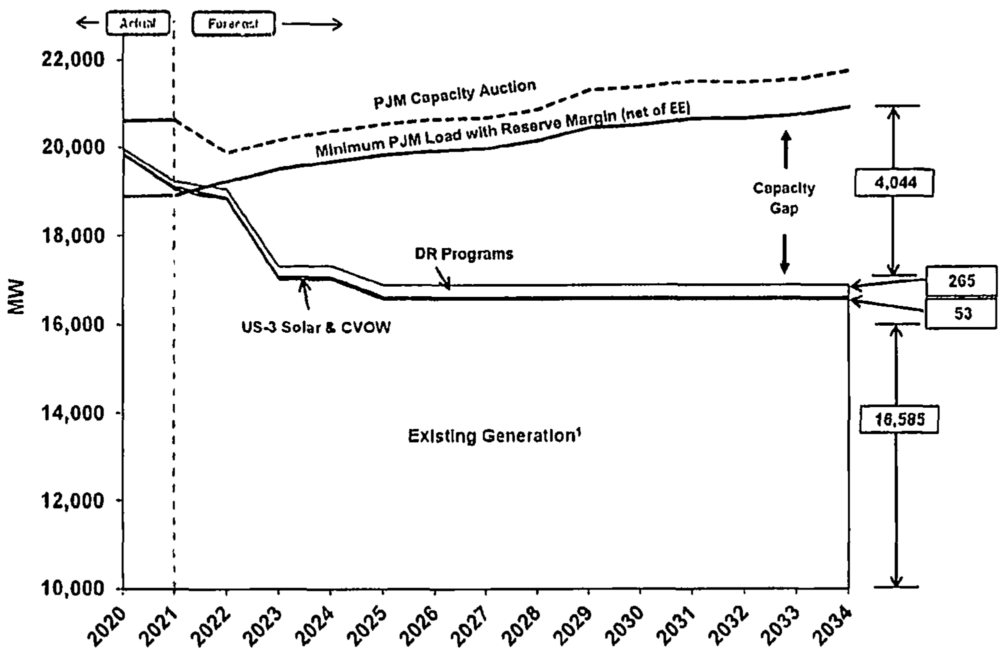
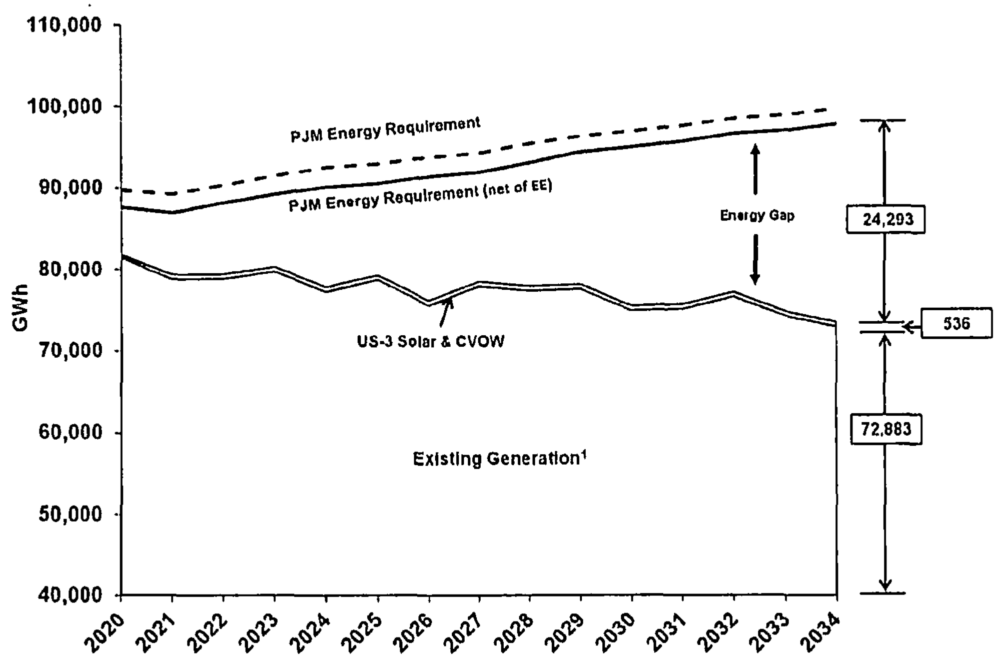


Figure 2: Energy Position



Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

c. Alternative Plans

The 2019 Update presents three alternative plans ("Alternative Plans") described below.

- Plan A: No CO_2 Tax – Plan A is based on the No CO_2 tax pricing scenario and is designed using least cost modeling methodology with no consideration of CO_2 emissions. Plan A represents the least cost plan consistent with the guidelines in prior SCC Orders.[16]

- Plan B: RGGI – Plan B assumes a pricing scenario where Virginia joins RGGI in 2021 and a Federal CO_2 Program is implemented in 2026. Plan B is designed such that the Company's generation expansion plan meets the objectives of the GTSA, in terms of solar and wind build and the battery pilot program. For clarity, Plan B assumes a scenario where Virginia joins RGGI through legislative action. Plan B is not based on linking to RGGI through the VDEQ action discussed in Section 2(a).

- Plan C: Sustainable Investment – Plan C assumes a pricing scenario where a Federal CO_2 Program is implemented in 2026. Plan C is designed such that the Company's generation expansion plan that meets the objectives of both the GTSA and SB 1418 in terms of solar and wind build, the battery pilot program, and pumped storage hydroelectric generation development.

[16] *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUE-2016-00049, Final Order (Dec. 14, 2016) at 4-5. *See also, generally, Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2018-00065, Order (Dec. 7, 2018) and Order on Reconsideration (July 19, 2019).

Figure 3: Alternative Plans

Year	Plan A: No CO_2 Tax	Plan B: RGGI	Plan C: Sustainable Investment
Approved and Generic DSM: 265 MW			
2020	US-3 Solar 1 (142 MW)	US-3 Solar 1 (142 MW)	US-3 Solar 1 (142 MW)
2021	CVOW US-3 Solar 2 (98 MW) US-4 Solar (100 MW) SLR NUG (20 MW) PP5	CVOW US-3 Solar 2 (98 MW) US-4 Solar (100 MW) SLR NUG (20 MW) BESS (12 MW)[1] PP5	CVOW US-3 Solar 2 (98 MW) US-4 Solar (100 MW) SLR NUG (20 MW) BESS (12 MW)[1] PP5
2022	CT GSLR (480 MW)	CT GSLR (480 MW)	CT GSLR (480 MW)
2023	CT YT3	BESS (14 MW)[1] CT GSLR (480 MW) CH 5-6 YT3	BESS (14 MW)[1] CT GSLR (480 MW) CH 5-6 YT3
2024	CT	CT GSLR (480 MW)	CT GSLR (480 MW)
2025		CT GSLR (480 MW) CL 1-2	CT OFF WIND (852 MW) CL 1-2
2026		CT GSLR (480 MW)	CT GSLR (480 MW)
2027		GSLR (480 MW)	
2028	GSLR (60 MW)		
2029	GSLR (240 MW)		
2030	GSLR (480 MW)		PMP STG (300 MW)
2031	GSLR (480 MW)	GSLR (360 MW)	GSLR (120 MW)
2032	GSLR (480 MW)	GSLR (480 MW)	GSLR (480 MW)
2033	GSLR (420 MW)	GSLR (240 MW)	GSLR (180 MW)
2034	GSLR (480 MW)	GSLR (480 MW)	GSLR (480 MW)

Key: BESS: Battery Energy Storage System; CH: Chesterfield Power Station; CL: Clover Power Station; CT: Combustion Turbine (2 units); CVOW: Coastal Virginia Offshore Wind Technology Advancement Project; GSLR: Generic Solar; PMP STG: Pump Storage; PP: Possum Point Power Station; SLR NUG: Solar NUG; US-3 Solar 1: US-3 Solar 1 Unit; US-3 Solar 2: US-3 2 Solar Unit; US-4 Solar: US-4 Solar Unit; YT: Yorktown Power Station;

Note: All references regarding new CT units throughout this document refer to a bank of 2 CT units (485 MW). CVOW was approved at 12 MW (nameplate).

1) The 12 MW BESS in Plans B and C represent the proposed BESS to be installed as a generation asset as part of the pilot program for the battery energy storage systems. The costs for Plans B and C also include the two additional 2 MW BESS proposed to be installed on the distribution system as part of the pilot program.

d. Net Present Value Comparison

The Company evaluated the Alternative Plans to compare and contrast the net present value ("NPV") utility costs over the Study Period. The Alternative Plans focus on the generation expansion plans to meet customers' demand. Figure 4 presents these NPV results as well as the estimated NPV of proposed investments in the Company's transmission and distribution systems, broken down by specific line item.

Figure 4: NPV Results

2019 $B	Plan A: No CO_2 Tax	Plan B: RGGI	Plan C: Sustainable Investment
Total System Costs[1]	$ 27.2	$ 31.1	$ 32.0
GT Plan[2]	$ -	$ 2.3	$ 2.3
SUP[2]	$ -	$ 1.5	$ 1.5
UG Pilot[2]	$ -	$ 0.4	$ 0.4
Transmission	$ 4.3	$ 4.3	$ 4.3
Customer Growth[3]	$ 1.7	$ 1.7	$ 1.7
Total Plan NPV	**$ 33.21**	**$ 41.22**	**$ 42.18**
Plan Delta vs. Plan A		$ 8.01	$ 8.97
Less Benefits of GT Plan[2]	$ -	$ (1.5)	$ (1.5)
Total Plan NPV	**$ 33.21**	**$ 39.73**	**$ 40.69**
Plan Delta vs. Plan A		**$ 6.52**	**$ 7.48**

Note: 1) Plan B forced in 3,000 MW (nameplate) solar and BESS. Plan C forced in everything included in Plan B, plus 300 MW (nameplate) pumped storage and 852 MW (nameplate) offshore wind. These total system costs include approved and generic DSM.

2) Costs for the GT Plan, Strategic Underground Program ("SUP"), and the Transmission Line Underground Pilot ("UG Pilot"), and benefits for the GT Plan, remain unchanged since the 2018 Compliance Filing, but were adjusted to 2019 dollars and an updated discount rate.

3) Customer growth includes distribution infrastructure and growth of future customer spend for 2019-2023.

4. LOAD FORECAST

For the 2019 Update, the Company followed the method used in the 2018 Compliance Filing for load forecasting.[17] Specifically, the Company utilized the PJM coincident peak demand and energy forecast for the Dominion Energy Zone ("DOM Zone") as published in PJM's January 2019 Load Forecast Report. Given that PJM does not provide a forecast for the DOM LSE, the DOM Zone forecast as published by PJM was scaled down. The DOM LSE percent of the DOM Zone was determined using a regression technique that utilizes historical peak and energy data over the preceding 10-year period.

Next, because the PJM forecast only provides a 15-year forecast, PJM's 15-year CAGR of 0.8% and 0.9% was used to extend the peak demand and energy forecasts, respectively, for years 2035 through 2044.

The Company standard for calculating reserve margins is based on peak load forecasts that net out peak load reductions resulting from energy efficiency ("EE") measures. Therefore, the next step in the process was to reduce the PJM coincident peak demand by the forecasted savings achieved at

[17] *See* SCC Dec. 2018 Order at 8.

peak from the approved EE programs, plus the generic EE program that is necessary to meet the objectives of the GTSA.

Figure 5 presents this scaled-down forecast, the forecast extensions, and the EE impacts on peak demand.

Figure 5 – PJM Coincident Peak Load Forecast

PJM 2019 - Dom Zone			PJM 2019 - LSE Equivalent				
Year	Coincident Peak (MW)	Energy (GWh)	Year	Coincident Peak (MW)	EE Approved + Generic Peak Reduction (MW)	EE Adjusted Coincident Peak (MW)	Energy (GWh)
2019	18,717	97,827	2019	16,276	271	16,006	85,325
2020	18,888	99,082	2020	16,425	276	16,149	86,419
2021	19,184	100,282	2021	16,682	346	16,336	87,466
2022	19,457	101,930	2022	16,920	299	16,621	88,903
2023	19,744	103,319	2023	17,169	302	16,867	90,115
2024	19,872	104,566	2024	17,281	266	17,015	91,202
2025	20,013	105,134	2025	17,403	259	17,144	91,698
2026	20,081	105,848	2026	17,462	246	17,216	92,321
2027	20,185	106,643	2027	17,553	278	17,275	93,014
2028	20,362	107,898	2028	17,707	277	17,430	94,109
2029	20,541	108,719	2029	17,862	165	17,697	94,825
2030	20,603	109,267	2030	17,916	164	17,753	95,303
2031	20,735	109,999	2031	18,031	161	17,870	95,941
2032	20,799	111,072	2032	18,087	204	17,883	96,877
2033	20,886	111,491	2033	18,162	210	17,953	97,242
2034	21,061	112,341	2034	18,315	210	18,105	97,984
2035	21,227	113,382	2035	18,459	232	18,227	98,892
2036	21,395	114,432	2036	18,605	145	18,460	99,808
2037	21,564	115,493	2037	18,752	205	18,547	100,733
2038	21,734	116,563	2038	18,900	206	18,694	101,666
2039	21,906	117,643	2039	19,049	236	18,814	102,608
2040	22,079	118,733	2040	19,200	231	18,969	103,559
2041	22,253	119,833	2041	19,351	150	19,202	104,518
2042	22,429	120,943	2042	19,504	204	19,300	105,486
2043	22,606	122,064	2043	19,658	206	19,452	106,464
2044	22,785	123,194	2044	19,813	234	19,579	107,450
2045	22,965	124,336	2045	19,970	239	19,731	108,446
2046	23,146	125,488	2046	20,128	239	19,889	109,451
CAGR 15-Yr =>	0.8%	0.9%	Average 10-Yr Reg =>	86.96%			87.22%

Next, the Company needed to determine how to incorporate this forecast into its model, PLEXOS. Planning models, including PLEXOS, require 8,760 hour (*i.e.*, the total hours in a year) load shapes ("8,760 load shapes") as a necessary input. PJM does not provide forecasted 8,760 load shapes. To solve this issue the Company used the following steps to come to a reasonable approximation of the scaled-down PJM coincident peak forecast:

- The Company utilized the non-coincident peak demand and energy forecast for the DOM Zone that was published by PJM in its January 2019 Load Forecast Report, scaled down to the DOM LSE level based on the Company's load ratio share of the DOM Zone and further adjusted by EE as described above.

- As a proxy to account for the magnitude of difference in PJM's coincident and non-coincident peak demand forecast, the Company adjusted the approximate 15.7% PJM planning reserve figure to lower the overall DOM Zone capacity needs consistent with PJM's coincident/non-coincident peak demand differences. This was done by calculating the average of the DOM Zone coincident/non-coincident peak ratio for the years 2019 through 2022, as published in PJM's 2019 Load Forecast Report. This calculation resulted in a diversification factor of approximately 96.60%.

- Using this diversification factor, the Company then adjusted PJM's full planning reserve figure of 15.7% using the following formula:

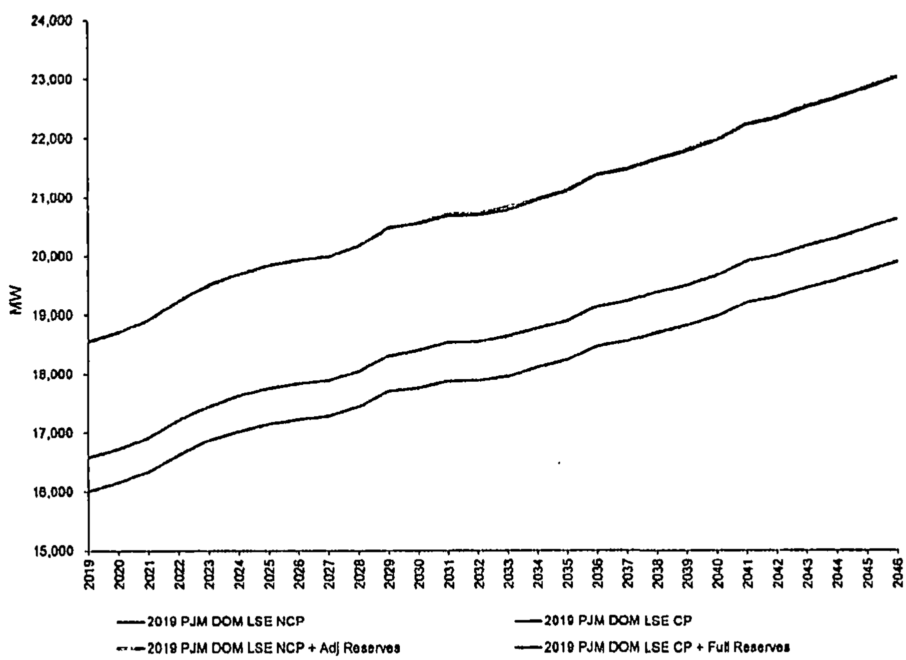
  *Adjusted Planning Reserves = [(1 + Full Planning Reserves) * Diversification Factor] - 1*

  Applying the above equation results in the Adjusted Planning Reserves equal to approximately 11.77%.

- This Adjusted Planning Reserve figure of 11.77% was then applied to PJM's 2019 DOM Zone non-coincident peak demand forecast adjusted for EE savings. This is in contrast to applying the full reserve figure of 15.7% to PJM's 2019 DOM Zone coincident peak forecast.

These adjustments result in a forecast that can be input into PLEXOS, and that reasonably approximates the PJM coincident peak plus full planning reserves of 15.7%, scaled down for the DOM LSE. Figure 6 presents the results of these adjustments.

Figure 6 – PJM 2019 Peak Demand Forecast – DOM LSE



As shown in Figure 6, the green line, which reflects the adjustments described above (*i.e.*, PJM DOM LSE non-coincident peak plus adjusted reserves), overlaps with the purple line, which reflects the PJM DOM LSE coincident peak plus full reserves. Figures 7 and 8 present the data supporting Figure 6.

Figure 7 – PJM 2019 Peak Demand Forecast – Coincident Peak

	PJM 2019 - LSE Equivalent				Reserve Calculations				
Year	Coincident Peak (MW)	EE Approved + Generic Peak Reduction (MW)	EE Adjusted Coincident Peak (MW)	Energy (GWh)	PJM Planning Reserves	Diversification Factor	Adjusted Reserves (MW)	Reserve Requirement (MW)	Total Resource Requirement (MW)
2019	16,276	271	16,006	85,325	15.9%	N/A	N/A	2,545	18,551
2020	16,425	276	16,149	86,419	15.8%	N/A	N/A	2,552	18,701
2021	16,682	346	16,336	87,466	15.8%	N/A	N/A	2,581	18,917
2022	16,920	299	16,621	88,903	15.7%	N/A	N/A	2,610	19,231
2023	17,169	302	16,867	90,115	15.7%	N/A	N/A	2,648	10,515
2024	17,281	266	17,015	91,202	15.7%	N/A	N/A	2,671	19,686
2025	17,403	259	17,144	91,698	15.7%	N/A	N/A	2,692	19,836
2026	17,462	246	17,216	92,321	15.7%	N/A	N/A	2,703	19,919
2027	17,553	278	17,275	93,014	15.7%	N/A	N/A	2,712	19,987
2028	17,707	277	17,430	94,109	15.7%	N/A	N/A	2,738	20,168
2029	17,862	165	17,697	94,825	15.7%	N/A	N/A	2,778	20,476
2030	17,916	164	17,753	95,303	15.7%	N/A	N/A	2,787	20,540
2031	18,031	161	17,870	95,941	15.7%	N/A	N/A	2,806	20,676
2032	18,087	204	17,883	96,877	15.7%	N/A	N/A	2,808	20,691
2033	18,162	210	17,953	97,242	15.7%	N/A	N/A	2,819	20,771
2034	18,315	210	18,105	97,984	15.7%	N/A	N/A	2,842	20,947
2035	18,459	232	18,227	98,892	15.7%	N/A	N/A	2,862	21,088
2036	18,605	145	18,460	99,608	15.7%	N/A	N/A	2,898	21,359
2037	18,752	205	18,547	100,733	15.7%	N/A	N/A	2,912	21,459
2038	18,900	206	18,694	101,666	15.7%	N/A	N/A	2,935	21,629
2039	19,049	236	18,814	102,608	15.7%	N/A	N/A	2,954	21,767
2040	19,200	231	18,969	103,559	15.7%	N/A	N/A	2,978	21,947
2041	19,351	150	19,202	104,518	15.7%	N/A	N/A	3,015	22,216
2042	19,504	204	19,300	105,486	15.7%	N/A	N/A	3,030	22,330
2043	19,658	206	19,452	106,464	15.7%	N/A	N/A	3,054	22,506
2044	19,813	234	19,579	107,450	15.7%	N/A	N/A	3,074	22,653
2045	19,970	239	19,731	108,446	15.7%	N/A	N/A	3,098	22,829
2046	20,128	239	19,889	109,451	15.7%	N/A	N/A	3,123	23,011

Average 10-Yr Reg =>	66.96%			67.22%

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Figure 8 – PJM 2019 Peak Demand Forecast – Non-Coincident Peak (Supporting Data)

	PJM 2019 - LSE Equivalent				Reserve Calculations				
Year	Non-Coincident Peak (MW)	EE Approved + Generic Peak Reduction (MW)	EE Adjusted Non-Coincident Peak (MW)	Energy (GWh)	PJM Planning Reserves	Diversification Factor	Adjusted Reserves	Reserve Requirement (MW)	Total Resource Requirement (MW)
2019	16,862	271	16,592	85,325	15.9%	96.60%	11.96%	1,984	18,576
2020	17,002	276	16,727	86,419	15.8%	96.60%	11.86%	1,984	18,711
2021	17,260	346	16,914	87,466	15.8%	96.60%	11.86%	2,006	18,920
2022	17,511	299	17,213	88,903	15.7%	96.60%	11.77%	2,025	19,238
2023	17,739	302	17,437	90,115	15.7%	96.60%	11.77%	2,052	19,488
2024	17,887	266	17,621	91,202	15.7%	96.60%	11.77%	2,073	19,694
2025	18,013	259	17,754	91,698	15.7%	96.60%	11.77%	2,089	19,843
2026	18,077	246	17,831	92,321	15.7%	96.60%	11.77%	2,098	19,929
2027	18,168	278	17,890	93,014	15.7%	96.60%	11.77%	2,105	19,995
2028	18,319	277	18,042	94,109	15.7%	96.60%	11.77%	2,123	20,165
2029	18,468	165	18,303	94,826	15.7%	96.60%	11.77%	2,154	20,457
2030	18,563	164	18,400	95,303	15.7%	96.60%	11.77%	2,165	20,565
2031	18,693	161	18,532	95,941	15.7%	96.60%	11.77%	2,180	20,712
2032	18,748	204	18,544	96,877	15.7%	96.60%	11.77%	2,182	20,726
2033	18,849	210	18,640	97,242	15.7%	96.60%	11.77%	2,193	20,833
2034	18,977	210	18,767	97,984	15.7%	96.60%	11.77%	2,208	20,976
2035	19,127	232	18,895	98,892	15.7%	96.60%	11.77%	2,223	21,118
2036	19,279	145	19,134	99,808	15.7%	96.60%	11.77%	2,251	21,385
2037	19,431	205	19,226	100,733	15.7%	96.60%	11.77%	2,262	21,488
2038	19,585	206	19,379	101,686	15.7%	96.60%	11.77%	2,280	21,659
2039	19,740	236	19,504	102,608	15.7%	96.60%	11.77%	2,295	21,799
2040	19,896	231	19,665	103,559	15.7%	96.60%	11.77%	2,314	21,979
2041	20,053	150	19,903	104,518	15.7%	96.60%	11.77%	2,342	22,245
2042	20,212	204	20,007	105,486	15.7%	96.60%	11.77%	2,354	22,361
2043	20,371	206	20,166	106,464	15.7%	96.60%	11.77%	2,373	22,538
2044	20,533	234	20,298	107,450	15.7%	96.60%	11.77%	2,388	22,687
2045	20,695	239	20,456	108,440	15.7%	96.60%	11.77%	2,407	22,863
2046	20,859	239	20,620	109,451	15.7%	96.60%	11.77%	2,426	23,046
Average 10-Yr Reg ⇨	88.06%			87.22%					

One final note, PJM reduces its load forecasts for behind-the-meter ("BTM") solar PV generation. Thus, to avoid double counting, the Company has not included any operating or expected BTM solar PV facilities in any PLEXOS modeling supply-side resources.

a. Economic Development Rates

As of August 1, 2019, the Company has six customer service locations in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 132 MW. As of August 1, 2019, the Company has no customers in North Carolina receiving service under economic development rates.

5. FUTURE SUPPLY-SIDE RESOURCES

The Company continues to gather information about emerging generation technologies from a mix of internal and external sources. The Company's internal knowledge base spans various departments including, but not limited to, planning, financial analysis, construction, operations, and business development. The dispatchable and non-dispatchable resources examined in this 2019 Update are discussed below.

a. Alternative Supply-Side Resources

The feasibility of utility-scale generation resources was evaluated on capital and operating expenses, including fuel, operation, and maintenance. Figure 9 summarizes the resource types that the Company reviewed as part of this IRP process. Those resources considered for further analysis in the busbar screening model are identified in the final column.

Figure 9: Alternative Supply-Side Resources

Resource	Unit Type	Dispatchable	Primary Fuel	Busbar Resource
Aero-derivative CT	Peak	Yes	Natural Gas	Yes
Batteries	Peak	Yes	Varies	Yes
Biomass	Baseload	Yes	Renewable	Yes
CC 1x1	Intermediate/Baseload	Yes	Natural Gas	Yes
CC 2x1	Intermediate/Baseload	Yes	Natural Gas	Yes
CC 3x1	Intermediate/Baseload	Yes	Natural Gas	Yes
CFB	Baseload	Yes	Coal	No
Coal (SCPC) w/ CCS	Intermediate	Yes	Coal	Yes
Coal (SCPC) w/o CCS	Baseload	Yes	Coal	No
CT	Peak	Yes	Natural Gas	Yes
Fuel Cell	Baseload	Yes	Natural Gas	Yes
Hydro Power	Intermittent	No	Renewable	No
IGCC CCS	Intermediate	Yes	Coal	Yes
IGCC w/o CCS	Baseload	Yes	Coal	No
Nuclear	Baseload	Yes	Uranium	Yes
Offshore Wind	Intermittent	No	Renewable	Yes
Onshore Wind	Intermittent	No	Renewable	Yes
Pumped Storage	Peak	Yes	Renewable	Yes
Reciprocating Engine CT	Peak	Yes	Natural Gas	No
Solar PV	Intermittent	No	Renewable	Yes
Solar PV w/Aero-derivative CT	Peak	Yes	Renewable	Yes
SMR	Baseload	Yes	Uranium	Yes

b. Busbar Analysis

The Company's busbar model was designed to estimate the levelized energy costs of various technologies on a level playing field. The busbar results show the levelized cost of power generation from a zero to one hundred percent capacity factor. The busbar results represent the Company's initial quantitative comparison of various alternative resources. These comparisons include: fuel, heat rate, emissions, variable and fixed operation and maintenance ("O&M") costs, expected service life, and overnight construction costs.

Figures 10 and 11 display high-level results of the busbar model comparing the costs of the different technologies. The results were separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources in terms of the energy and capacity value they provide to customers. For example, dispatchable resources are able to generate when power prices are the highest, while non-dispatchable resources may not have the ability to do so. Furthermore, non-dispatchable resources typically receive less capacity value for meeting the Company's reserve margin requirements and may require additional technologies in order to assure grid stability.

Figure 10: Dispatchable Levelized Busbar Costs (2022 COD)

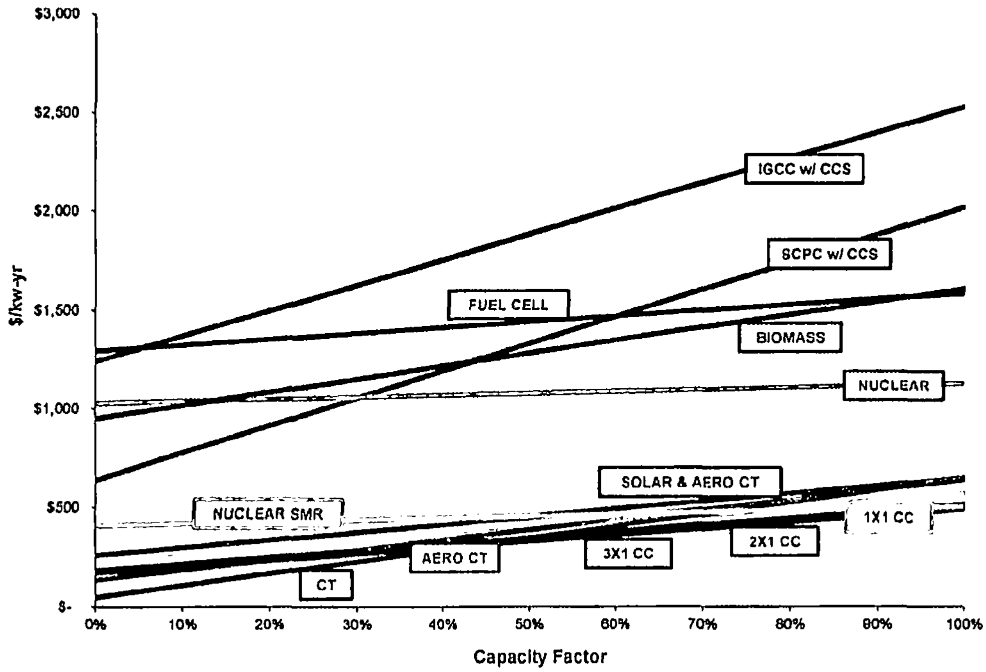
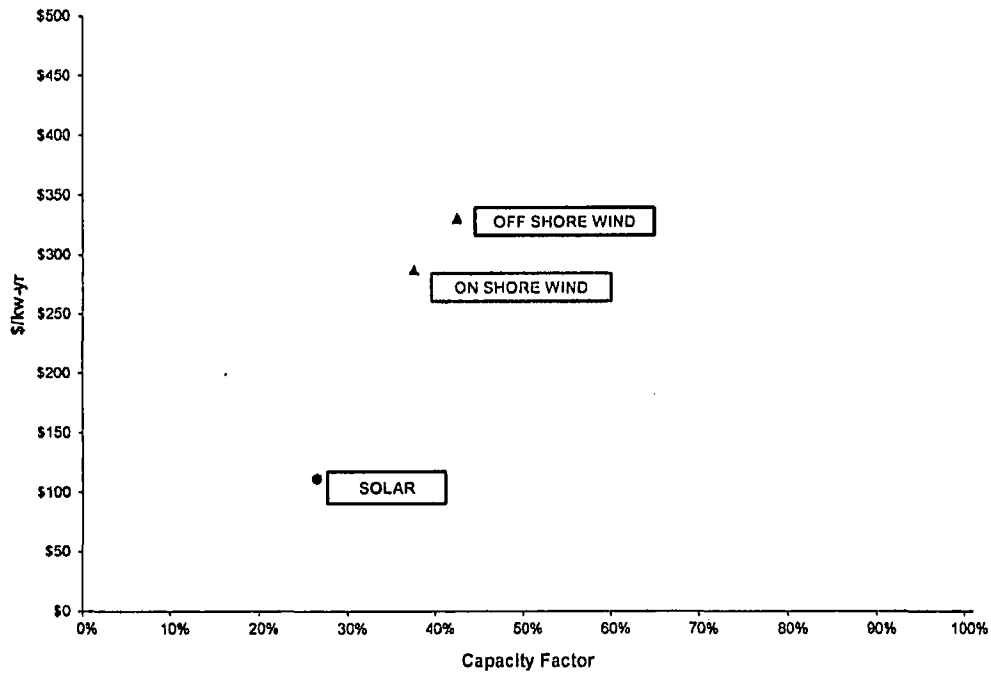


Figure 11: Non-Dispatchable Levelized Busbar Costs (2022 COD)

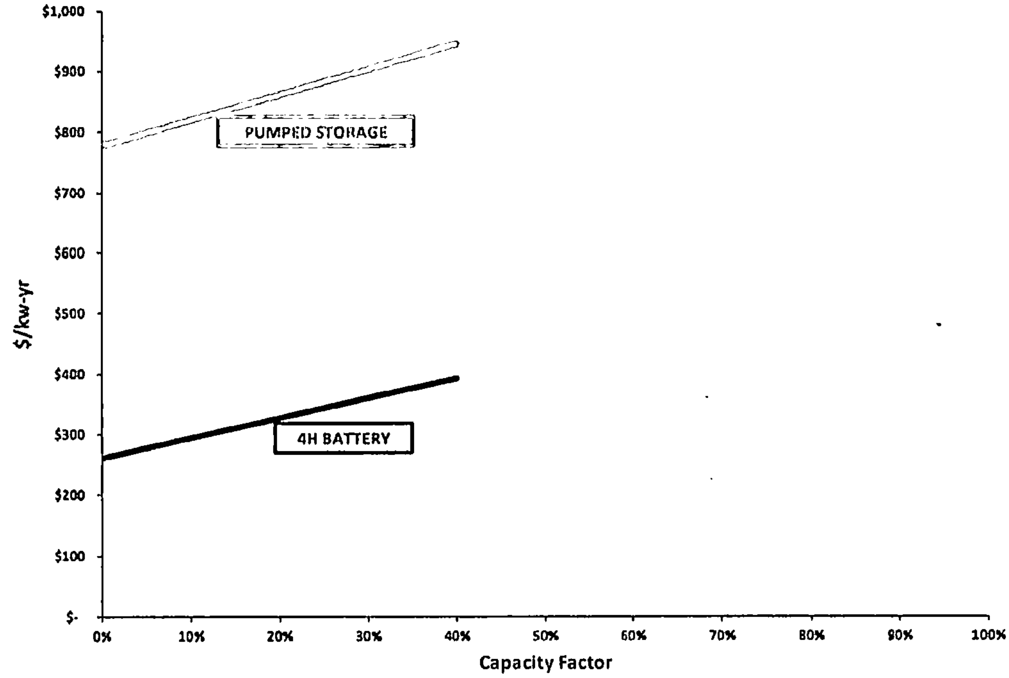


c. Energy Storage Technologies

There are several different types of energy storage technologies. Energy storage technologies include, but are not limited to, pumped storage hydroelectric power, superconducting magnetic energy storage, capacitors, compressed air energy storage, flywheels, and batteries. Cost considerations and technology maturity have restricted widespread deployment of most of these technologies, with the exception of pumped storage hydroelectric power and batteries.

Figure 12 shows the estimated levelized busbar costs for a 4-hour battery and a pumped storage facility from a zero to a forty percent capacity factor. Batteries and pumped storage technologies are incapable of achieving more than a forty percent capacity factor, due to their charging requirements.

Figure 12: Energy Storage Levelized Busbar Costs (2022 COD)



i. Pumped Storage

There is increasing interest in pumped storage technology as a storage mechanism for the intermittent and highly variable output of renewable energy sources such as solar and wind. For example, as discussed above, SB 1418 supports the construction of "one or more pumped hydroelectric generation and storage facilities that utilize on-site or off-site renewable energy resources as all or a portion of their power source and such facilities and associated resources are located in the coalfield region of the Commonwealth."

Following the approval of SB 1418 in 2017, the Company entered into the early stages of conducting feasibility studies for a potential pumped storage facility in the western part of the Commonwealth of Virginia. Pumped storage is a proven dispatchable technology that would complement the ongoing integration of renewable resources.

The Company continues to evaluate the construction of a proposed pumped hydroelectric storage power station at a site in Tazewell County, Virginia, and will spend the remainder of this year and part of next year conducting more extensive surveys of the proposed site. In addition, the project could generate thousands of construction jobs as well as provide a major new source of local taxes for the region. The facility would store energy from traditional sources, such as the Company's coal-fired VCHEC, as well as renewable facilities.

ii. Battery Storage

In addition to pumped storage, the Company continues to monitor advancements in batteries. The Company is in the early stages of battery research and has relied on publicly available industry guidance regarding battery storage projects to help evaluate the technology's merits as compared to traditional generation sources. Battery storage is a viable future option for peak shifting at a stand-alone storage facility or co-located at a solar facility. Battery storage may also improve overall energy production at a solar facility by capturing energy that may be clipped by the inverters. A solar inverter converts the variable direct current ("DC") output of a PV panel into a utility frequency alternating current ("AC") that can be fed into the electric grid. Inverter clipping occurs when a solar inverter has reached maximum capacity for energy output. To avoid damage to the unit, it will "clip" any additional power that solar panels produce. This is a standard operating condition when designing systems with an oversized panel array.

Since battery storage facilities are still in early stages of development, the cost estimates for installation are more reflective of a pilot program versus a larger utility-scale facility. Indeed, the Company submitted its first application to participate in the battery pilot program established by the GTSA, as discussed further in Section 7(d) of this Update.

The Company included battery and pumped storage facilities in the busbar analysis discussed above.

6. PLANNING ASSUMPTIONS

a. PJM Capacity Value for Renewable Resources

PJM Manual 21 describes the "capacity value" (also referred to as "UCAP" or unforced capacity) of wind or solar generating resources as class average value for immature units and output during summer peak hours (3:00 PM-6:00 PM) for units with historical operating data.[18] The "capacity value" referenced in Manual 21 sets a cap for what a wind or solar resource "can be offered as unforced capacity into the PJM capacity markets."[19] Note that the "capacity value" language in Manual 21 predates the Capacity Performance ("CP") construct by several years.

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[18] *See* https://www.pjm.com/~/media/documents/manuals/m21.ashx, Appendix B at pp. 34-36.
[19] *See* https://www.pjm.com/~/media/documents/manuals/m21.ashx, Appendix B.2.1 at p. 34.

Under the CP construct, it was PJM's expectation that the quantity of UCAP value that may qualify as CP for such resources may be based on expected output during summer and winter peak conditions.

Recently, PJM has developed the Effective Load Carrying Capability ("ELCC")-based approach for wind or solar capacity value, which is expected to replace the current class average method.[20] As opposed to the existing PJM class average capacity value, the ELCC-based value is a metric directly related to the wind or solar resource's ability to serve load without impact to system reliability. While this approach is still being discussed in the PJM stakeholder process, the preliminary wind or solar value (Wind ELCC = 12.3%, Solar ELCC = 45.1%) may more reasonably reflect the resource's potential bid value in the upcoming capacity auction. This capacity bid value can be offered into the capacity auction as annual, seasonal or aggregate capacity, or a combination thereof.

b. Commodity Price Forecast

The Company utilizes a single source to provide multiple scenarios for the commodity price forecast to ensure consistency in methodologies and assumptions. The Company performed the analysis in this 2019 Update using energy and commodity price forecasts provided by ICF for all periods except the first 36 months of the Study Period. The forecasts used for natural gas, coal, and power prices rely on forward market prices as of June 28, 2019, for the first 18 months of the Study Period and then blended forward prices with ICF estimates for the next 18 months. Beyond the first 36 months, the Company used the ICF commodity price forecast exclusively. The forecast used for capacity prices were provided by ICF for all years forecasted in the 2019 Update. The capacity prices are provided on a calendar year basis and reflect the results of the PJM Reliability Pricing Model ("RPM") BRA through the 2021/2022 delivery year, thereafter transitioning to the ICF capacity forecast beginning with the 2022/2023 delivery year.

The key assumptions on market structure and the use of an integrated, internally consistent fundamentals-based modeling methodology remain consistent with those utilized in the prior years' commodity forecasts. In the 2019 Update, the Company utilizes three commodity forecasts to evaluate the Alternative Plans:

- No CO_2 Tax commodity forecast
- RGGI + Federal CO_2 Tax commodity forecast
- Federal CO_2 Tax commodity forecast

In the two commodity forecasts that consider Federal CO_2 Tax programs, the assumptions for CO_2 regulation represent a probability-weighted outcome of legislative and regulatory initiatives, including the possibility of no regulatory program addressing CO_2 emissions. The probability-weighted approach to the CO_2 price forecast is consistent with the methodology utilized in evaluation of prior Plans. In both forecasts, a charge on CO_2 emissions from the power sector at the federal level is assumed to begin in 2026. The difference between the two forecasts is that in one forecast it is assumed Virginia joins the RGGI program in 2021, and in the other forecast it is assumed that Virginia does not take state-level action on CO_2 regulation.

[20] *See* https://www.pjm.com/-/media/committees-groups/committees/mrc/20190321/20190321-item-03c-m21-revisions-presentation.ashx.

The No CO_2 Tax commodity forecast anticipates a future without any new regulations or restrictions on CO_2 emissions, so the cost associated with carbon emissions is removed from the commodity forecast. To be clear, the Company expects that some form of GHG regulations or legislation will occur, and is planning accordingly. The No CO_2 Tax forecast is only utilized in analysis of Plan A; in this way, Plan A provides a benchmark against which to measure the cost of GHG program compliance.

Appendix 4A provides the annual prices (nominal $) for the RGGI + Federal CO_2 Tax commodity forecast, the Federal CO_2 Tax commodity forecast, and the No CO_2 Tax commodity forecast. Figure 13 provides a comparison of the three commodity forecasts with the forecast used in the 2018 Plan.

Figure 13: 2018 Plan vs. 2019 Update Fuel & Power Price Comparison

	2019 - 2033 Average Value (Nominal $)	2020 - 2034 Average Value (Nominal $)		
Fuel Price	2018 Plan Federal CO_2 commodity forecast	RGGI + Federal CO_2 Tax commodity forecast	Federal CO_2 Tax commodity forecast	No CO_2 Tax commodity forecast
Henry Hub Natural Gas ($/MMbtu)	4.29	3.81	3.81	3.81
Zone 5 Delivered Natural Gas ($/MMbtu)	3.71	3.54	3.54	3.54
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	2.66	2.42	2.42	2.43
1% No. 6 Oil ($/MMbtu)	11.93	11.56	11.56	11.56
Electric and REC Prices				
PJM-DOM On-Peak ($/MWh)	41.29	38.94	38.66	38.56
PJM-DOM Off-Peak ($/MWh)	34.36	32.79	32.55	32.41
PJM Tier 1 REC Prices ($/MWh)	7.04	6.72	6.95	7.27
RTO Capacity Prices ($/kW-yr)	59.33	62.50	62.74	60.46

i. Forecasting of Long-Term Capacity Prices

In most wholesale electricity markets, electric power generators are paid for providing:

- Energy: the actual electricity consumed by customers;
- Capacity: standing ready to provide a specified amount of electric energy; and
- Ancillary Services: a variety of operations needed to maintain grid stability and security, including frequency control, spinning reserves, and operating reserves.

The purpose of a mandatory capacity market is to encourage new investments where they are most needed on the grid. PJM's capacity market (*i.e.*, the RPM), ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted peak demand in the future. In a capacity market, the utility or other electricity supplier are required to have enough resources to meet its customers' demand plus a reserve amount. Suppliers can meet that requirement with generating capacity they own, with capacity purchased from others under contract, or with capacity obtained through market auctions.

RPM prices are intended to provide additional revenue to attract and maintain sufficient capacity; in concept, revenues from energy and ancillary services plus capacity payments should equal the amount necessary to attract new entry. These capacity payments provide an incentive for generators to locate in that market and they help guarantee that there will be sufficient generation to meet the maximum energy requirements of the market at all times. As stated by the PJM Market Monitor: "In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources."[21]

Parallel to the actual market construct, forecasting of long-term capacity prices are based on estimating the amount of capacity revenue a generation resource requires, in addition to revenue from energy and ancillary services, to maintain reliable electric service over the long-term. The capacity revenue forecast represents the amount by which a resource's cost exceeds its forecasted wholesale electricity market revenues. The basic concept utilized in forecasting is that in order to maintain appropriate reserve levels to assure reliable electric service, generating resources will require sufficient revenue to cover expenses and, when necessary, support the required new investment. When wholesale market, energy, and ancillary services revenue is not sufficient, then capacity revenues are required.

When forecasting capacity prices over long periods of time, it is reasonable to assume markets will move toward equilibrium and provide sufficient revenue to support existing resources and incent investment in new resources that require equity returns on the capital expended for development and construction of the resource. In markets with excess capacity, existing resources generally set the capacity price. These resources require revenue to cover only operating expenses and do not include equity returns or significant going forward capital expenditures. Because of this, the capacity price tends to be lower. However, over the long term, the market is expected to move to an equilibrium status where sufficient revenues are provided, which assures adequate resource capacity and encourages market efficiency. Note, while long-term forecasts tend toward an equilibrium pricing, it is expected that actual markets will continue to follow an up and down cycle that moves around equilibrium levels. Long-term forecasts for capacity focus on the equilibrium level pricing rather than attempting to estimate the cyclical movement.

7. SHORT-TERM ACTION PLAN

The Short-Term Action Plan ("STAP") provides the Company's strategic plan for the next five years (2020 to 2024), as well as a discussion of the specific short-term actions the Company is taking to meet the initiatives discussed in the 2018 Plan and the 2019 Update. The Company continues to proactively position itself in the short term to address the evolving developments surrounding future CO_2 emission mitigation rules or regulations, as well as societal and customer preferences for the benefit of all stakeholders over the long term. Over the next five years, the Company expects to:

- Continue development of planning processes that will reasonably assess the actions and costs associated with the integration of large volumes of intermittent renewable generation on the transmission and distribution systems;
- Enhance and upgrade the Company's existing transmission and distribution systems, enhancing reliability and customer service;
- Enhance the Company's access to natural gas supplies, including shale gas supplies from multiple supply basins;

[21] 2019 Quarterly State of the Market Report for PJM, at p. 1, Monitoring Analytics, LLC. *See* https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019q1-som-pjm.pdf.

- Construct additional generation to meet customer demand while maintaining a balanced fuel mix;
- Continue to lower the Company's emissions footprint;
- Continue to develop and implement a renewable strategy that supports the Virginia renewable generation objectives identified in the GTSA, the Virginia Renewable Portfolio Standard ("RPS") goals, and the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") requirements;
- Propose and implement cost-effective programs based on measures identified in the 2017 DSM Potential Study and continue to implement cost-effective DSM programs in Virginia and North Carolina as developed through the stakeholder process required by the GTSA and at the levels for proposal set forth in the GTSA; and
- Continue to evaluate potential unit retirements in light of changing market conditions and regulatory requirements.

A more detailed discussion of the activities over the next five years is provided in the following sections.

a. Generation Resources

Over the next five years, the Company expects to take the following actions related to existing and proposed generation resources:

- Continue development of the CVOW facility along with the first tranche of utility-scale offshore wind generation;
- Continue the development of the energy storage alternatives, including battery storage and the development activities associated with a new pumped storage hydroelectric generation facility in western Virginia;
- Pursue a certificate of public convenience and necessity ("CPCN") for US-4 Solar, which was filed on July 23, 2019, with the SCC;
- Place the US-3 Solar Units 1 and 2 (240 MW) into service by the end of 2019;
- Continue technical evaluations and aging management programs required to support an SLR to extend the Company's existing Surry Units 1 and 2 and North Anna Units 1 and 2; and
- Submit an application for the second renewed operating licenses for Surry Units 1 and 2 by the end of the first quarter of 2019, and for North Anna Units 1 and 2 by the end of 2020.

Appendix 3K provides a summary of the generation under construction included in the Alternative Plans along with the forecasted in-service dates and summer/winter capacities. Appendix 5C provides the projected in-service dates and capacities for generation resources under development for the Alternative Plans.

b. *Renewable Energy Resources*

Approximately 532 MW of qualifying renewable generation is currently in operation:

- Solar: approximately 261 MW;
- Hydroelectric: approximately 220 MW; and
- Biomass: approximately 51 MW.

Over the next five years, the Company expects to take the following actions regarding renewable energy resources:

Virginia

- Achieve 61 MW of biomass capacity at VCHEC by 2023;
- Meet its targets under the Virginia RPS Program by applying renewable generation from existing qualified facilities and purchasing cost-effective renewable energy certificates ("RECs"); and
- Submit its Annual Report to the SCC detailing its efforts towards the RPS plan.

North Carolina

- Submit its 2019 REPS Compliance Report for compliance year 2018 in August 2019;
- Submit its annual REPS Compliance Plan (filed with the North Carolina 2019 Update); and
- Enter into or negotiate power purchased agreements ("PPAs") with approximately 680 MW (nameplate) of North Carolina solar NUGs by 2020.

c. Transmission

Virginia

- The following planned Virginia transmission projects detailed are pending SCC approval or are tentatively planned for filing with the SCC:
  - Line #574 Elmont to Ladysmith Rebuild
  - Line #581 Chancellor to Ladysmith 500 kV Rebuild
  - Line #29 Fredericksburg to Possum Point Partial Rebuild
  - Line #205 and Line #2003 Chesterfield to Tyler Partial Rebuild
  - Line #552 Bristers to Chancellor Rebuild
  - Line #205 and Line #2003 Chesterfield to Tyler Partial Rebuild

- o Line #2023 & Line #248 Potomac Yards Undergrounding & Glebe GIS Conversion
- o Line #550 Mount Storm to Valley Rebuild
- o Line #247 Suffolk to Swamp Rebuild
- o Line #2209 and Line #2110 Evergreen Mills 230 kV Delivery
- o Line #224 Lanexa to Northern Neck Rebuild
- o Lockridge 230 kV Delivery
- o Global Plaza 230 kV Delivery
- o Line #2173 Loudoun to Elklick Rebuild
- o Line #295 and Partial Line #265 Rebuild
- o Lines #265, #200, and #2051 Partial Rebuild
- o Line #2008 Partial Rebuild and Line #156 Retirement
- o Line #2063 and Partial #2164 Rebuild

Appendix 3R lists the major transmission additions including line voltage and expected operation target dates. A list of the Company's transmission lines and associated facilities that are under construction can be found in Appendix 3X.

d. Energy Storage Technologies

On August 2, 2019, the Company submitted its first application to participate in the pilot program for electric power storage batteries established by the SCC pursuant to the GTSA. The application presents three projects for deployment of battery energy storage systems (*i.e.*, BESS) as part of the Pilot Program: BESS-1: Prevention of Solar Backfeeding; BESS-2: BESS as a Non-Wires Alternative; and BESS-3: Solar Plus Storage. Through BESS-1, the Company proposes to deploy a 2 MW / 4 MWh AC lithium-ion BESS that will study the prevention of solar backfeeding onto the transmission grid at a specific substation. Through BESS-2, the Company proposes to deploy a 2 MW / 4 MWh AC lithium-ion BESS that will study BESS as a non-wires alternative to reduce transformer loading at a specific substation. Through BESS-3, the Company proposes to study solar plus storage by deploying a lithium-ion BESS at its Scott Solar Facility consisting of a 2 MW / 8 MWh DC-coupled system and a 10 MW / 40 MWh AC-coupled system. The aggregate capacity of the proposals included with this application is 16 MW. The Company may seek approval of additional BESS in future applications up to the 30 MW authorized under the pilot program.

Following the approval of SB 1418 in 2017, the Company entered into the early stages of conducting feasibility studies for a potential pumped storage facility in the western part of the Commonwealth of Virginia. The Company continues to evaluate the construction of a proposed pumped hydroelectric storage power station at a site in Tazewell County, Virginia, and will spend the remainder of this year and part of next year conducting more extensive surveys of the proposed site.

e. Demand-Side Management

The DSM stakeholder process, as established by the GTSA, began in 2019, and will provide valuable input into the planning process into the foreseeable future. The Company issued a request for proposals ("RFP") in April 2019 and provided the 2017 DSM Potential Study to vendors to develop bids. The Company is currently in the process of evaluating the bids, and the results potentially will be included in future Company filings. The Company commissioned a new Market Potential Study in second quarter 2019, to identify potential measures that could be included in future Company-sponsored programs. The Company is committed to meeting the GTSA requirement to propose $870 million of DSM programs through 2028, and will include additional measures in DSM programs in future Plans. The measures included in the commissioned 2019 DSM Potential Study still need to be part of a program design effort that looks at the viability of the potential measures as a single or multi-measure DSM program. These fully designed DSM programs would also need to be evaluated for cost-effectiveness and included in future Plan and DSM filings. The Company included in this 2019 Update the approved 11 DSM programs from Case No. PUR-2018-00168. On July 12, 2019, in Docket Nos. E-22, Sub 567, 568, 569, 570, 571, 572, 573, and 574, the Company filed for approval of the Residential Appliance Recycling Program, Residential Efficient Products Marketplace Program, Residential Home Energy Assessment Program, Non-Residential Lighting Systems & Controls Program, Non-Residential Heating and Cooling Efficiency Program, Non-Residential Window Film Program, Non-Residential Small Manufacturing Program, and Non-Residential Office Program. The Company is currently awaiting a final order on these program applications.

Like the 2018 Compliance Filing, the 2019 Update includes a Generic EE program designed to achieve the target of $870 million of EE expenditures by 2028. The Company determined the balance of the EE energy reductions necessary to achieve this $870 million goal given a generic program cost of $200/MWh and also given the forecasted energy savings from EE programs currently approved by the SCC.

i. <u>Approved DSM Programs</u>

On October 3, 2017, as part of Case No. PUR-2017-00129, the Company filed for a five-year extension of the Phase IV Residential Income & Age Qualifying Home Improvement Program. On May 10, 2018, the SCC issued its Final Order approving the Residential Income and Age Qualifying Home Improvement Program for three years.

On October 3, 2018, the Company filed for SCC approval in Case No. PUR-2018-00168 of six residential DSM programs and five non-residential DSM programs. The 11 proposed programs were the (i) Residential Appliance Recycling Program, (ii) Residential Customer Engagement Program, (iii) Residential Efficient Products Marketplace Program, (iv) Residential Home Energy Assessment Program, (v) Residential Smart Thermostat Management Program (DR), (vi) Residential Smart Thermostat Management Program (EE), (vii) Non-Residential Lighting Systems & Controls Program, (viii) Non-Residential Heating and Cooling Efficiency Program, (ix) Non-Residential Window Film Program, (x) Non-Residential Small Manufacturing Program, and (xi) Non-Residential Office Program. On May 2, 2019, the SCC issued its Final Order approving all 11 programs for a five-year period.

In North Carolina, the Company filed a Motion to Reopen the Residential Income and Age Qualifying Home Improvement Program on May 31, 2018, in Docket No. E-22, Sub 523. On June 26, 2018, the NCUC issued an order reopening this program.

On August 16, 2018, the Company filed for approval of two North Carolina-only programs in Docket Nos. E-22, Sub 507 and 508. The two programs were the Non-Residential Heating and Cooling Efficiency Program and the Non-Residential Lighting Systems & Controls Program. On October 16, 2018, the NCUC issued Final Orders approving both programs.

ii. Cost/Benefit Analysis

Since the 2018 Compliance Filing, the following DSM cases with cost-benefit scores were filed in North Carolina: Docket Nos. E-22, Sub 567, 568, 569, 570, 571, 572, 573, 574, and 577. The filings in these dockets reflect the most current information available. No additional analysis has been completed related to cost-benefit for DSM programs.

f. Grid Transformation Plan

Consistent with the policy objectives of the Commonwealth set forth in the GTSA, the Company has developed a plan to transform its electric distribution grid (*i.e.*, the Grid Transformation Plan or GT Plan) to address the structural limitations of the Company's distribution grid in a systematic manner, recognizing and accommodating fundamental changes in the electric industry and changing customer expectations.

The Grid Transformation Plan is a 10-year plan that includes six components: (i) advanced metering infrastructure ("AMI"); (ii) a new customer information platform ("CIP"); (iii) grid improvements, which include grid technologies and grid hardening; (iv) telecommunications infrastructure; (v) cyber and physical security; and (vi) emerging technology, which will include an initiative focused on electric vehicles charging infrastructure.

In 2018, the Company petitioned the SCC for approval of the first three years of the GT Plan ("Phase I") in Case No. PUR-2018-00100. The SCC approved proposed Phase I investments related to cyber and physical security, including supporting telecommunications infrastructure, as reasonable and prudent. The SCC denied the remaining portions of the proposed Phase I, but did so without prejudice to the Company seeking approval of the GT Plan in future petitions.

Since the Final Order was entered in Case No. PUR-2018-00100, the Company has been working diligently to address the concerns raised by the SCC, its Staff, and other parties to last year's GT Plan proceeding. Among other action items, the Company convened a series of stakeholder meetings to receive input and feedback on next steps for the Grid Transformation Plan, and solicited specific customer feedback on the GT Plan. Based on this feedback, the Company has been refining its proposed investments to ensure alignment with the objectives of grid transformation. In addition, the Company has retained an independent, experienced, third-party partner to generate a benefit-cost analysis for the GT Plan. The Company plans to file its second petition for approval of GT Plan investments later this year.

8. APPENDIX

The appendices listed below have been updated for the 2019 Update. Note that Appendices 2A through 2F are not able to be provided with PJM's 2019 Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class. To comply with all prior relevant orders and rules, and as the PJM breakdown is not available, the Company is providing

Appendices 2A through 2G using the Company's 2019 Load Forecast. Note, however, that this information was not used to develop the PJM load forecast.

a. **Appendix 1A (Capacity and Energy)**

b. **Appendix 2A (Total Sales by Customer Class)**

c. **Appendix 2B (Virginia Sales by Customer Class)**

d. **Appendix 2C (North Carolina Sales by Customer Class)**

e. **Appendix 2D (Total Customer Count)**

f. **Appendix 2E (Virginia Customer Count)**

g. **Appendix 2F (North Carolina Customer Count)**

h. **Appendix 2G (Zonal Summer and Winter Peak Demand)**

i. **Appendix 2H (Summer and Winter Peaks)**

j. **Appendix 2I (Projected Summer & Winter Peak Demand & Annual Energy)**

k. **Appendix 2J (Required Reserve Margin)**

l. **Appendix 3A (Existing Generation in Service)**

m. **Appendix 3B (Other Generation Units)**

n. **Appendix 3J (Potential Unit Retirements)**

o. **Appendix 3K (Generation Under Construction)**

p. **Appendix 3L (Wholesale Power Contracts)**

q. **Appendix 3M (Description of Recently Approved DSM Programs)**

r. **Appendix 3R (List of Planned Transmission Projects)**

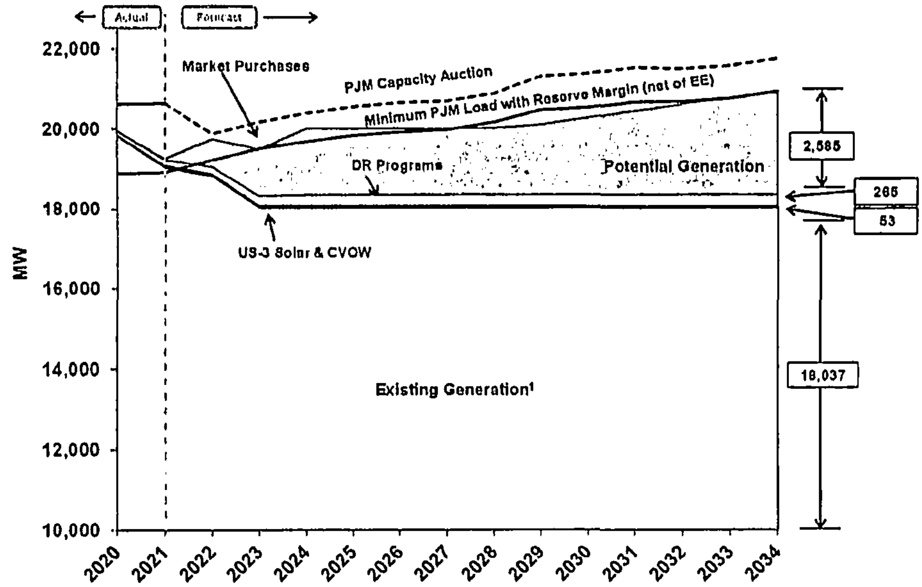
s. **Appendix 3X (List of Transmission Projects Under Construction)**

t. **Appendix 4A (ICF Commodity Price Forecast)**

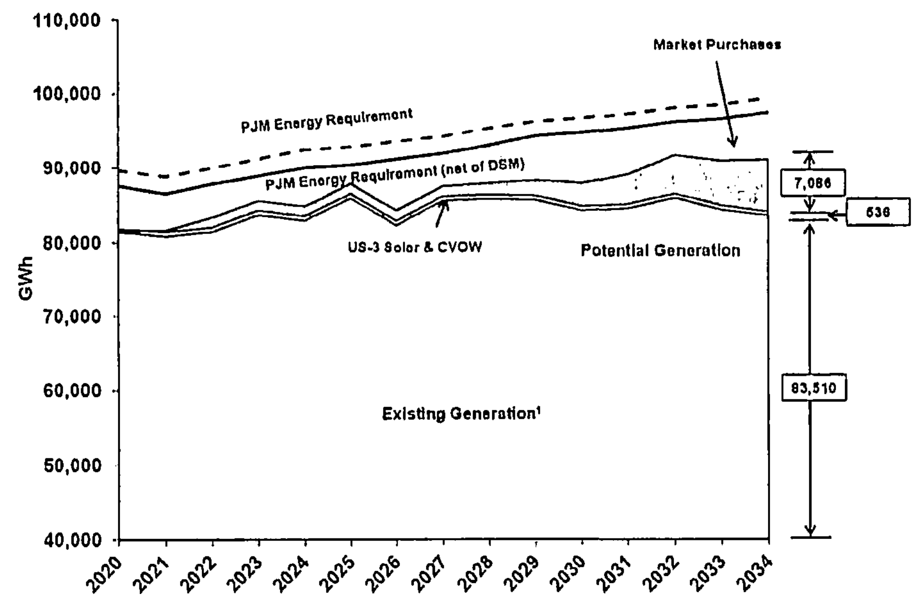
u. **Appendix 5C (Planned Generation Under Development)**

Appendix 1A: Plan A: No CO_2 Tax – Capacity and Energy

Capacity



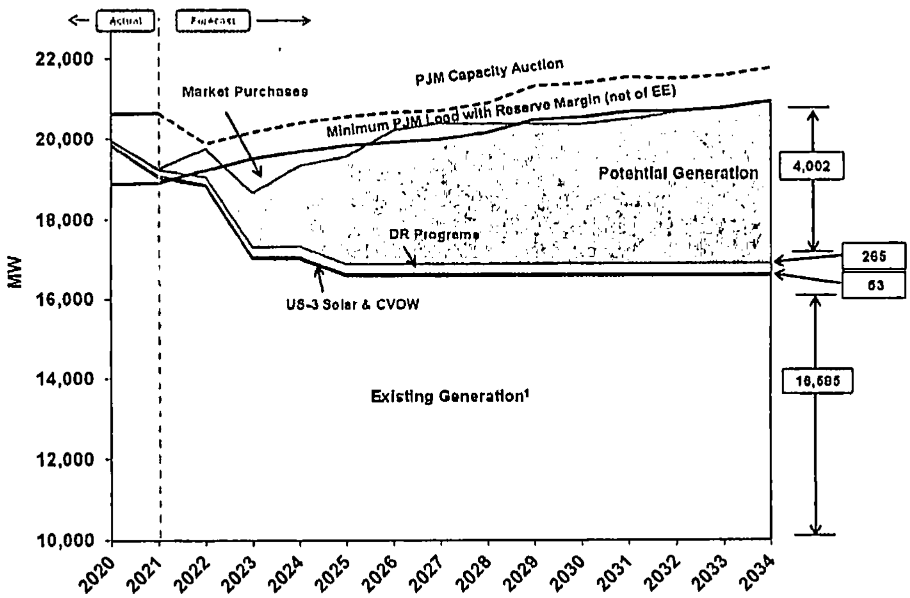
Energy



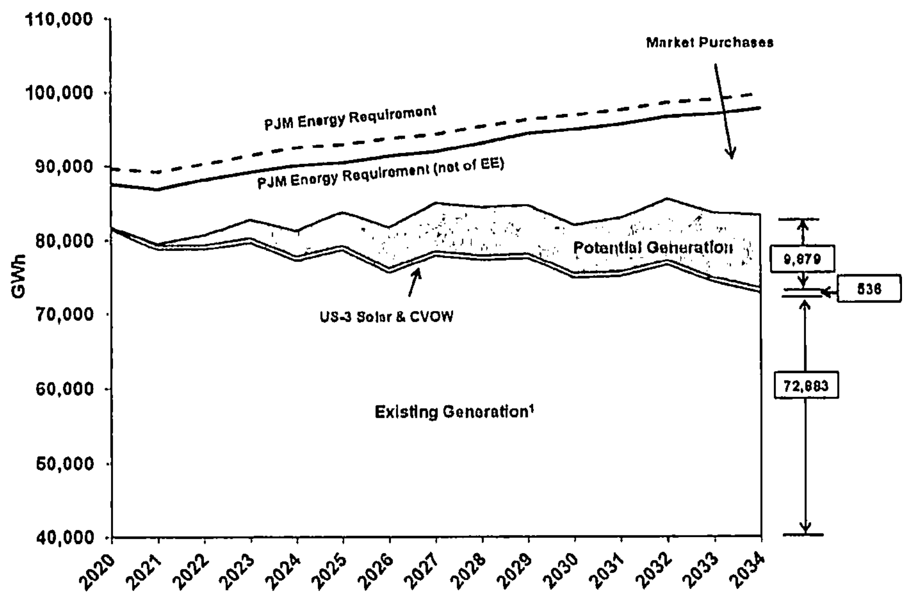
Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A: Plan B: RGGI – Capacity and Energy

Capacity



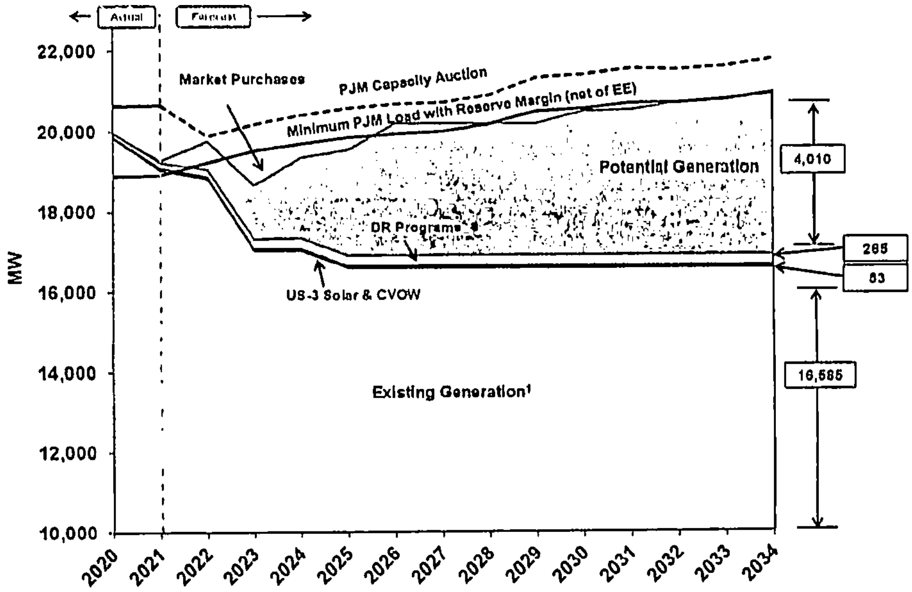
Energy



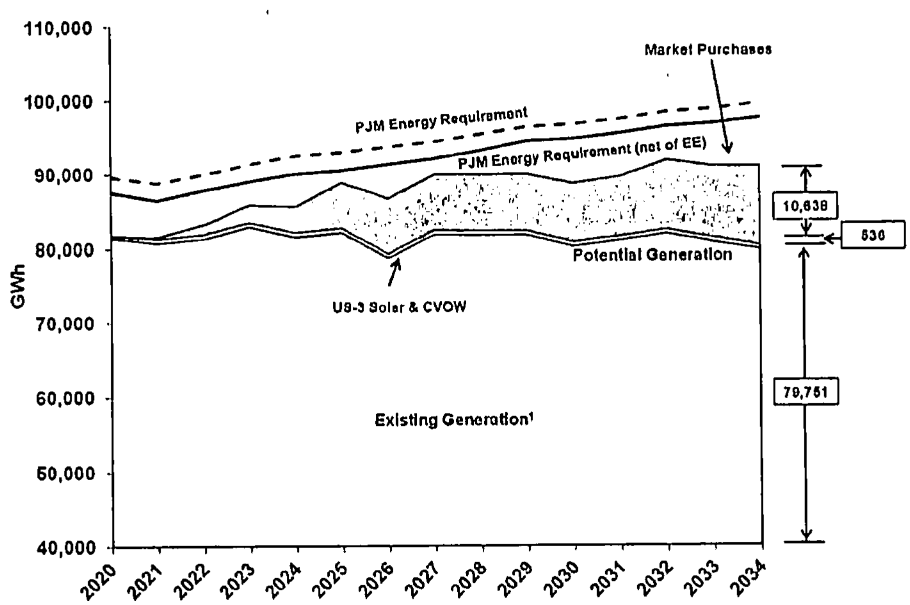
Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A: Plan C: Sustainable Investment – Capacity and Energy

Capacity



Energy



Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 2A: Total Sales by Customer Class (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	29,646	28,484	9,779	10,529	282	1,990	80,710
2009	29,904	28,455	8,644	10,448	276	1,932	79,658
2010	32,547	29,233	8,512	10,670	281	1,921	83,164
2011	30,779	28,957	7,960	10,555	273	2,011	80,536
2012	29,174	28,927	7,849	10,496	277	1,984	78,709
2013	30,184	29,372	8,097	10,261	276	1,956	80,145
2014	31,290	29,964	8,812	10,402	261	1,981	82,710
2015	30,923	30,282	8,765	10,159	275	1,856	82,260
2016	28,213	31,366	8,715	10,161	253	1,609	80,318
2017	29,737	32,292	8,638	10,555	258	1,607	83,086
2018	32,139	33,591	8,324	10,761	260	1,633	86,707
2019	31,236	32,807	8,990	10,330	280	1,560	85,203
2020	31,518	33,311	8,952	10,368	281	1,581	86,012
2021	31,758	34,166	8,788	10,422	282	1,594	87,010
2022	32,028	35,123	8,610	10,487	283	1,609	88,140
2023	32,364	35,954	8,447	10,635	284	1,625	89,308
2024	32,776	37,443	8,359	10,769	284	1,647	91,277
2025	32,972	38,708	8,327	10,801	285	1,658	92,753
2026	33,270	39,845	8,336	10,933	286	1,675	94,345
2027	33,551	41,138	8,340	11,036	287	1,694	96,046
2028	34,007	42,506	8,360	11,173	288	1,719	98,053
2029	34,304	43,540	8,317	11,342	289	1,738	99,529
2030	34,677	44,554	8,306	11,515	290	1,760	101,101
2031	35,110	45,690	8,364	11,459	291	1,779	102,693
2032	35,594	46,777	8,368	11,730	291	1,801	104,561
2033	35,866	47,559	8,345	11,767	292	1,822	105,651
2034	36,221	48,462	8,326	11,703	293	1,836	106,840

Note: Historic (2008 – 2018). Projected (2019 – 2034).

Based on the Company's internal forecast; information not provided by PJM Load Forecast.